Section A3
Alternative 3, Rotary Kiln Gasification

ing at both – gaseous and molten phase – system outlets, homogeneous phases are obtained corresponding to high temperature equil rium states. De-novo-synthesis (reformation) of organic compounds (like PCDD/F) and formation of nitrogen oxides is avoided, p duction of ash and filter ash is excluded.

The following paper describes the process with special emphasis on the degasification, gasification and smelting secti Experiences obtained from an industrial scale plant are presented.

THE KRUPP UHDE PRECON® PROCESS BASED ON THE HIGH-TEMPERATURE-WINKLER (HTW) GASIFICATION FOR PROCESSING SOLID WASTES

Dr.-Ing. Christoph Lütge, Dipl.-Ing. Marco Deutsch
Krupp Uhde GmbH
Friedrich-Uhde-Strasse 15
44141 Dortmund, Germany
Dr.-Ing. Rainer Wischnewski, Dr.-Ing. H.-P. Schiffer
Rheinbraun AG
Stüttgenweg 2
50935 Cologne, Germany
David L. Hoey
Molten Metal Technology, Inc.
400-2 Totten-Pond Road
Waltham, MA 02154, USA

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ABSTRACT

In recent years, there has been an ever greater demand for the treatment of solid wastes (e.g. municipal solid waste (MSW), a shredder residue (ASR), sewage sludge) in Germany and other European countries. In particular, there is no public acceptance for dumping of solid wastes, because of unforeseeable consequences in the future. Thermal treatment is an ideal mean to transform a sel part of the waste stream into an environmentally harmless and less voluminous substance while simultaneously recovering its energy co tent. The possibility of converting waste to energy makes the thermal treatment of solid wastes even more attractive.

ENERGY RECOVERY FROM SOLID WASTE FUELS USING ADVANCED GASIFICATION TECHNOLOGY

Michael Morris and Lars Waldheim
TPS Termiska Processer AB
Studsvik
611 82 Nyköping
Sweden

ABSTRACT

Since the mid. 1980's, TPS Termiska Processer AB has been working on the development of an atmospheric-pressure gasificati process. A major aim at the start of this work was the generation of fuel gas from indigenous fuels to Sweden (i.e.biomass). As the ec nomic climate changed and awareness of the damage to the environment caused by the use of fossil fuels in power generation equipm increased, the aim of the development work at TPS was changed to applying the process to heat and power generation from feedstoc such as biomass and solid wastes. Compared with modern waste incineration with heat recovery, the gasification process will permit increase in electricity output of up to 50%.

The gasification process being developed is based on an atmospheric-pressure circulating fluidised bed gasifier coupled to a t cracking vessel. The gas produced from this process is then cooled and cleaned in conventional equipment. The energy-rich gas produc is clean enough to be fired in a gas boiler (and, in the longer term, in an engine or gas turbine) without requiring extensive flue gas cle ing, as is normally required in conventional waste incineration plants. Producing clean fuel gas in this manner, which facilitates the u of efficient gas-fired boilers, means that overall plant electrical efficiencies of close to 30% can be achieved.

TPS has performed a considerable amount of pilot plant testing on waste fuels in their gasification/gas cleaning pilot plant Sweden. Two gasifiers of TPS design have been in operation in Grève-in-Chianti, Italy since 199. This plant processes 200 tonnes RDF (refuse-derived fuel) per day.

It is planned that the complete TPS gasification process (including the complete fuel gas cleaning system) be demonstrated in se eral gas turbine-based biomass-fuelled power generatinof the world. Start-up of the first plant is scheduled for1999.

It is the aim of TPS to prove, at commercial scale, the technical feasibility and economic advantages of the gasification process wh it is applied to solid waste fuels. This aim shall be achieved, in the short-term, by employing the cold clean product gas in a gas boi and, in the longer-term, by firing the gas in engines and gas turbines. A study for a 90MWth waste-fuelled co-generation plant in Swec has shown that, already today, gasification of solid waste can compete economically with conventional incineration technologies.

Keywords: biomass, waste, RDF, CFB, gasification, tar cracking, combined-cycle, IGCC, corrosion

STEAM REFORMING OF LOW-LEVEL MIXED WASTE

Gary E. Voelker, William G. Steedman
ThermoChem, Inc.
10220-H Old Columbia Road
Columbia, MD 21046
Ravi R.Chandran
Manufacturing and Technology Conversion International, Inc.
10020-G Old Columbia Road
Columbia, MD 21046

ABSTRACT

The U.S. Department of Energy (DOE) is responsible for the treatment and disposal of an inventory of approximately 160,000 t of Low-Level Mixed Waste (LLMW). Most of this LLMW is stored in drums, barrels and steel boxes at 20 different sites throughout DOE complex. The basic objective of low-level mixed waste treatment systems is to completely destroy the hazardous constituents

PROPERTIES OF ENERGY RECOVERY BY COMBUSTION OF INDUSTRIAL WASTE AND COAL PREMIX FUELS

Motohiro Kondoh and Masataka Yamaguchi
Plant Engineering Department
TOYOTA MOTOR CORP.
Toyota-shi, Aichi-ken, Japan
Shigekatsu Mori
Department of Chemical Engineering
Graduate School of Nagoya University
Nagoya-shi, Aichi-ken, Japan

ABSTRACT

With the call intensifying for globally addressing the earth's environmental problems, demand for increased efficiency in utilizing resources and energy is growing. Waste-related problems, in particular, as they have been addressed with a focus on volume reduction and proper disposal, have raised a new area awaiting research: Can waste be a viable source of energy?

Among a number of types of waste, one that is receiving great interest is industrial waste, which is generated from manufacturing production and is discharged to communities in many diverse forms. The present study has been conducted with a focus on identifying the recovery characteristics of electr · and thermal energy from combustion using a cogeneration system and industri : waste as the main fuel

Conventional methods of power generation from waste have been limited by the degree to which the steam pressure and temperature in the energy recovery boiler for can be increased, due to the effects of the corrosive compositions of waste that attack the furnace casing.

In the present study, coal and waste were premixed and incinerated, then evaluated for their combustion characteristics, with the aims of achieving a method that ensures high temperature, high pressure, and sufficiently stable steam recovery. Industrial waste is characterized by its highly diverse mix of many different kinds of waste. Since identifying its combustion characteristics and conducting stable combustion based on the characteristics thus identified are critical in increasing energy recovery efficiency and consequently improving power generation efficiency, a two-furnace construction for the combustion furnace was employed leading to a highly effective solution to the problem found in conventional methods and also leading to the attainment of our objectives. In the present study we have evaluated combustion characteristics which have attained stability through the combustion of premixed industrial waste and coal, while paying special attention to the combustion characteristics of fluidized bed combustion of coal alone, along with evaluating the characteristics of the exhaust gases resulting from combustion. We have then conducted an evaluation to determine heat recovery characteristics and the other conditions required for increasing the 10% power generation efficiency that can be attained in conventional waste power generation systems to a maximum power generation efficiency of 24%, by recovering steam at a higher temperature and a higher pressure (60 atg./460°C). This paper also describes the operating results of an actualsystem that was run in the light the findings of the present study and discusses the effects that this system has shown.

As the world increases its awareness of the necessity of building a recycling society, a wide variety of approaches have been set out to deal with waste-related problems. Looking at a series of recent moves toward legislation in response to this trend, including the enforcement of the Recycling Law and the revision of the Waste Disposal Act in Japan, makes us renew our recognition of how serious a social issue current waste-related problems present.

Against this background, the industrial world has been called upon to address such problems, urging individual industries to make efforts in their own ways. In addition to these individual efforts, nurturing a sound and effective waste-disposal and recycling industry are of critical importance, since delay in achieving this may undermine the foundation for growth in the entire industrial world.

In recent years, in the search for compatibility between the environment and energy, using a highly efficient cogeneration power generan proposed as one viable method of recovering and utilizing energy from industrial waste, a source of energy which has yet to be exploited. When it comes to constructing a cogeneration system using waste as fuel, however, two major technological problems have manifested themselves as gross hindrances; they are (1) how can high-temperature corrosion by the attack of HCl and other exhaust gases generated from waste can be prevented, and (2) how can non flammables contained in waste can be dealt with without causing any adverse effects?

Meanwhile, coal, a solid fuel, is inferior in physical and chemical properties as a fuel compared to petroleum. With the aim of expanding demand for coal, studies are being conducted widely on fluidized bed combustion technology, which is a combustion technology that may make coal a stable and homogeneous fuel.

In the present study, coal and waste have been premixed and incinerated, then evaluated for their combustion characteristics, while paying special attention to the combustion characteristics of coal alone in fluidized bed combustion, with the aim of achieving a method that ensures high temperature, high pressure, and sufficiently stable steam recovery. The present study has also analyzed the results of this evaluation in order to identify the conditions required for stable combustion and obtain knowledge of heat recovery characteristics and other matters.

This paper also describes the operating results of an actual system that was run in the light of the findings of the present study and discusses the effects that this system has shown.

MODEL PREDICTIVE CONTROL AND ON-LINE OPTIMIZATION OF A SELECTIVE CATALYTIC REACTOR FOR NOX REMOVAL IN INCINERATION PLANTS

M. Rovaglio, D. Manca, M.G. Berretta, F. Rusconi
CIIC - Dipartimento di Chimica Industriale ed Ingegneria Chimica "G. Natta"
Politecnico di Milano
P.zza Leonardo da Vinci 32 20133 Milano, Italy

ABSTRACT

This paper presents the results regarding the application of a simulation tool as supervisory system for NOx removal in a municipal waste incineration plant.

The optimization procedure consists of the search of the best working conditions that satisfy the operating and legal constraints, in terms of emission amounts and combustion quality. This procedure adopts a simulation algorithm and data reconciliation tool to verify and improve the consistency of the calculated values by experimental data.

In order to optimize the DeNOx section performance, a reliable simulation model must include a detailed description of each plant section and the formation/reduction kinetics of different pollutants throughout the different units.

INCORPORATION OF INTERMEDIATE-LEVEL LIQUID RADIOACTIVE NUCLEAR POWER PLANT WASTES IN GLASS AND CERAMICS

F.A. Lifanov, A.P. Kobelev, S.V. Stefanovsky, V.I. Kornev, V.N. Zakharenko, M.A. Polkanov,
T.N. Lashtchenova, V.A. Solovyov, O.A. Knyazev, E.A. Kachalova, O.V. Tolstova, and O.I. Kirjanova
SIA "Radon"
7th Rostovskii per. 2/14, Moscow 119121 Russia

ABSTRACT

SIA "Radon" experience in development and testing of glassy and ceramic compositions suitable for low- and intermediate level liquid waste (LILLW) immobilization is described. Various borosilicate and aluminophosphate glasses, as well as aluminosilicate ceramics, were proposed to immobilize both institutional and Nuclear Power Plant (NPP) wastes. Institutional LILLW and NPP waste from RBMK containing sodium nitrate as major component, can be effectively incorporated in aluminosilicate and borosilicate glasses. Waste oxide content in these glasses reaches 35-40 wt.%. NPP waste from VVER should be preferably immobilized in borosilicate glasses providing waste oxide content up to 45-50 wt.%. To incorporate sulfate- and chloride-bearing wastes in glass, aluminophosphate matrices are preferable. An alternative for sulfate-chloride-bearing waste immobilization is ceramic route with formation of clay-based aluminosilicate ceramic. All the materials obtained have low leachability (leach rate of ^{137}Cs – 10^{-5}-10^{-6} g · cm^{-2} · day^{-1}).

SESSION 18A: PART I: DESIGN AND MODIFICATION EFFECTS ON OPERATIONS

DESIGN, START UP AND RETROFIT - A TALE OF THREE INCINERATORS AT A RESEARCH BASED PHARMACEUTICAL COMPANY

Scott A. Lauer
Superintendent
Solid Waste Management-Incineration
Merck & Company, Inc.
P. O Box 4 Mailstop WP20-206
West Point, PA 19486-0004

ABSTRACT

Not that long ago, those involved in the incineration of non-hazardous waste only needed to be concerned about feed rates, temperature limitations and the possibility of black smoke pouring from the stack in order to comply with environmental regulations of the 1970's and 1980's. With the event of the Clean Air Act and increasingly strict permit conditions, anyone who wanted to stay in the incineration business had to spend significant time and capital to obtain permits and build/retrofit their incinerators. Several plant sites associated with one major research-based pharmaceutical company decided that it was worth running the gauntlet to pursue upgrading the on-site incineration capacity at their facilities. Although favorable pricing for many (but not all) waste streams was available at the larger commercial incinerator facilities, on-site processing was selected because of liability issues associated with off site shipments.

At one of those plant sites, there exist three incinerators that span the evolutionary process - the retrofit of an existing stepped hearth incinerator, decommissioning of a rotary kiln, and the construction/operation of a new rotary kiln from scratch. These three units are used to process the site's general plant trash, off-spec pharmaceuticals and their byproducts, low level radioactive waste, infectious materials and other manufacturing waste streams. There are distinct advantages and disadvantages associated with each of these machines, with regard to cost, throughput, maintenance and operation.

Each of these three incinerators is unique, and the associated issues are diverse, yet instructive.

THE UPGRADING OF THE UK'S LARGEST MUNICIPAL EFW FACILITY AT EDMONTON, LONDON TO MEET NEW EMISSION LIMITS AND PROPOSED EC YEAR 2001 STANDARDS

Brian M. Heap
Managing Director
PROCEDAIR LTD
Midland House, Ounsdale Road
Wombourne, Wolverhampton
West Midlands WV5 8BY
England

ABSTRACT

The beginning of the 1990's saw a major shift in the control of environmental pollution in the UK. The main reason for this was the introduction of the Environmental Protection Act (1990) legislation which became law in April 1991.

Whilst this was to influence all sectors of industry to some degree, it was to have significant impact on the waste incineration sector. The scale of the impact can be judged against the fact that of the 30 municipal waste incineration (MWI) facilities operating in 1991, only 3 would be operational as upgraded by 1 December 1996 deadline. The other 27 were either closed (20), being upgraded (1), totally rebuilt (1) or in the process of being totally rebuilt (5). One new plant on a new site was also operational.

One of the three facilities which were upgraded was the largest in the UK at Edmonton, North London, which treated over 500,000 Te/year of municipal waste and exported 32 MW of electricity.

The project involved change of ownership, financing, competitive tendering and contract implementation and completion.

This was a major challenge in itself which was compounded by several delays in the pre-contract stage, culminating in only 16 months being left available for the design, fabrication, installation and commissioning of a £15 million ($24 million) retrofit on a fully operational plant.

Despite this, the project was completed both on time and in budget and more importantly, the performances achieved during acceptance testing established a new set of benchmarks and ensured the facility could meet emission requirements proposed for the year 2001.

The selection decisions made the experiences gained and the operating results will be explored in the paper and its presentation.

Biomass Power Program
Vermont Gasifier Project

Project Summary

The Vermont Gasifier project is part of a major U.S. Department of Energy (DOE) initiative to demonstrate gasification of renewable biomass for electricity production. The Vermont Project has been undertaken to demonstrate the integration of the Battelle Columbus Laboratories (Battelle) "indirect" gasifier with a high-efficiency gas turbine. The demonstration and validation of this gasification/gas turbine system is being undertaken at the existing 50 megawatt wood-fired McNeil Power Generating Station in Burlington, Vermont, thereby significantly reducing the time-scale for deployment and the necessary capital investment for DOE and the Vermont project partnership. The development and commercialization of this technology is important for several reasons:

1) It does not require a hot-gas cleanup for gas turbine operation, thus removing this technical hurdle from the commercialization path;

2) It is the only biomass gasification system in the world that has successfully powered a gas turbine, proving its near-term viability for commercial deployment; and

3) It produces a higher BTU gas stream than other gasification systems, thus allowing the use of exising unmodified industrial gas turbines.

FY 1996 Products

The project's detailed design will be completed and construction will be initiated on a 15 megawatt installation that will complement the existing 50 megawatt output of McNeil Station.

Payoffs

Demonstration of this U.S. technology at a utility power station will significantly buy-down the perceived risk among domestic and international power project developers. It will also provide significant market opportunities for advanced-cycle, high-efficiency biomass power generation systems for application in domestic and international markets. Successful demonstration will provide substantial market pull for U.S. biomass gasification technologies, and provide a significant market edge over competing foreign technologies.

Status

Currently, Zurn Nepco, an engineering company with extensive experience in the design and construction of biomass-fired power plants, is preparing the detailed engineering design and is completing the permitting process for the start of construction, which is scheduled for late 1995. Operation and debugging of the gasifier component is forecast for 1996, and the addition of the gas turbine is forecast for 1997.

Partners and Cost Share

The Vermont Project is a scale-up of an indirect gasifier concept developed by Battelle, which is based in Columbus, Ohio. The principal industrial partner, Future Energy Resources Company (FERCO), of Atlanta, Georgia, is cost-sharing 50% of the overall project costs with DOE. Other project participants include the co-owners of the McNeil generating station located in Burlington, Vermont, which is operated by the Burlington Electric Department, and Zurn Nepco, of Portland, Maine.

Related Programs

This project parallels the Hawaii Biomass Gasifier Facility project in many respects. The Battelle indirect gasifier technology to be used in the Vermont project features several innovations that may offer advantages over air/oxygen blown gasification systems. One advantage is that it generates a fuel-gas that is free of atmospheric nitrogen, which makes it capable of easy catalytic cleanup prior to either combustion or use in the chemical synthesis of methanol, a future automobile fuel. The product gas has about half the heating value of natural gas, unlike other air-blown gasifiers that produce a biogas with a much lower heating value. As a consequence, existing gas turbines can be used with this fuel-gas without modification.

DOE's Office of Transportation Technologies operates the Biofuels Development Program that is developing liquid fuels from biomass through gasification technologies, with a strong emphasis on the use of biotechnology to produce ethanol from lignocellulosics (such as woody or grassy materials). As such, the technology development and validation to be accomplished under this program directly benefits DOE's Biofuels Program as well.

Vulnerabilities and Issues

The major vulnerability concerns the worldwide competition for biomass gasification technologies. Currently, there are several biomass gasification commercialization activities underway in North America, Brazil, and Scandinavia. Two promonent international developments (the World Bank's Global Environmental Facility Gasifier Project in Brazil, and the Varnarmo Bioflo project in Sweden) indicate the European biomass gasification technologies are also close to commercial demonstration, which could provide direct international competition for this developing market. It is critical that U.S. tehcnologies not lose out to foreign interests in this vast arena of market opportunity. Accordingly, further development, demonstration, and deployment of this technology could be jeopardized should funding for this Biomass Power project be reduced.

June 1995

For Further Information Contact:
Energy Efficiency and Renewable Energy Clearinghouse (EREC)
(800) 363-3732 Return to Biomass Power Program

U.S. DEPARTMENT OF ENERGY
BIOPOWER
RENEWABLE ELECTRICITY FOR LOCAL COMMUNITIES

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FY 1995-FY 1996 Biomass Power Program Accomplishments

Promoted Commercialization of Biomass Power Through Joint Ventures

- Issued a solicitation for a 5-year, $80 million program to demonstrate Biomass Power for Rural Development.

FY 1993-FY 1994 Biomass Power Program Accomplishments

Promoted Commercialization of Biomass Power Through Joint Ventures

- Dedicated an industrial-scale biomass gasification facility.
- Tested a hot-gas cleanup system with gasified biomass.
- Supported 10 feasibility studies for integrating feedstock supply with biomass power facility development.

Improved Today's Technology Through Partnerships with Industry and Power Producers

- Conducted cofiring studies and tests with the Tennessee Valley Authority.
- Worked with biomass power plant operators, industry, and researchers to characterize the chemical and physical mechanisms of alkali deposits in boilers.
- Supported development of direct-fired gas turbine operating on wood and coal.
- Developed the Advanced Transportable Molecular Beam Mass Spectrometer to bring analytical laboratory capabilities to biomass power plants developed by the Biomass Power Program.

Developed New Technologies

- Operated the world's first system using biogas from a gasifier to fuel a natural gas turbine-generator.
- Produced and tested "biocrude" oil for combustion properties.

Reduced Technical and Nontechnical Barriers to Commercialization

- Supported efforts of the National Biofuels Roundtable to develop principles and guidelines for biomass energy systems.
- Sponsored the First Biomass Conference of the Americas and made plans for the second.
- Supported work of the Utility Biomass Energy Commercialization Association.

February 27, 1998

Contact: Kevin McQuigg
Vice President, Process Engineering

BIOENERGY '98
BIOMASS GASIFICATION ABSTRACT

STARVED AIR GASIFICATION TESTS ON FIVE BIOMASS FEEDSTOCKS

As a subcontractor on SERBEP contract TV-01420W, Primenergy, Inc. performed gasification tests on five different biomass materials (switchgrass, paper pulp sludge, rice straw, sugar cane bagasse and poultry litter) at its demonstration gasification system in Tulsa, Oklahoma. The tests were completed on September 25, 1997.

The gasification process employed by Primenergy's demonstration gasification system a starved air, atmospheric, staged combustion process. The existing test equipment has the capacity to gasify approximately 30 tons per day of a typical biomass feedstock. A satisfactory test requires 30 to 40 tons of feedstock for two to three preliminary tests and a final sustained run of about 12 hours in order to obtain certified emissions measurements (NOx, CO, NMHC, SOx and PM) by a third party testing company.

For the gasification process, approximately 30 to 40% of the biomass' stoichiometric air (underfire air) is injected into the gasifier to control the gasifier temperature at the selected temperature (typically 1200 to 1500°F). The resulting starved air combustion converts the organic material in the biomass to a "biogas" with a heating value of approximately 175 Btu/dscf. Primary combustible constituents of the biogas are methane, ethane, carbon monoxide and hydrogen. Inert diluents of nitrogen, water vapor and carbon dioxide are present in large amounts, thereby reducing the heating value of the biogas. The size of the gasifier results in extremely low gas velocities, minimizing (but not entirely eliminating) ash carryover to downstream equipment. In the second stage of combustion (the overfire combustion chamber) an additional 10 to 20% of the stoichiometric air is introduced into the hot biogas at a controlled rate to reach an intermediate temperature of 2000 to 2400°F. This high temperature in a reducing atmosphere converts nitrogen bound compounds (NH_3, HCN, NOx, etc.) from the biomass to molecular nitrogen (N_2) instead of NOx. The third and final stage of combustion occurs with excess air injection at temperatures ranging from 1600 to 1800°F to oxidize the combustibles from the second stage.

The paper discusses biomass feedstock preparation; gasifier and overfire combustion chamber operating conditions, emission results, and slagging characteristics for each of the five biomass materials.

Return to Primenergy's Hot News

PRIMENERGY, INC.

Typical System Description

The Biomass Gasification system includes: the fuel metering bin and structure, the patented KC Reactor/Gasifier, the combustion tube and chamber, the gasifier cooling water system, water cooled ash discharge conveyors, multi-zoned gasification air supply, multi-zoned combustion air supply, rotary feeders and instrumentation required to provide automatic control over the process.

The KC Reactor/Gasifier consists of a high temperature refractory lined cylindrical steel shell that is mounted in a vertical position on heavy structural steel supports. The lower portion of the reactor contains an appropriately sized fixed grate. The cross sectional area of the upper portion of the gasifier is reduced to provide the turbulence required to ensure proper mixing of the product gas and the combustion air that is introduced into this area of the gasifier. The refractory lining consist of the appropriate thickness of insulating castable and high-temperature dense castable that is applied by guning after the shell is erected. The lining is secured by stainless steel anchor clips attached to the shell.

Fuel is metered to the gasifier from the fabricated steel metering bin. The bin is equipped with level controls, an infeed leveling conveyor and a variable speed outfeed conveyor that delivers fuel to the gasifier. The speed of the outfeed conveyor is automatically adjusted by the gasifier control system to maintain a pre-set first stage gasification zone temperature. The discharge from the out feed conveyor is directed through an impact weigh metering device that provides precise indication and control of the fuel feed rate. The feed system is installed complete with the necessary support steel, platforms and access ladders. The first stage temperature setpoint is manually adjusted to compensate for the average moisture contect of the fuel being gasified.

Fuel is introduced into the gasifier by a water-cooled screw conveyor that discharges into the drying and heating zone of the gasifier. The gasification process is controlled by the proportioned injection of gasification and combustion air in a manner that supports efficient gasification. Residence time in the gasifier is varied by a residence control system that is adjusted to achieve the desired carbon content of the ash discharged from the gasifier. The use of mechanical bed agitation, precise gasification air control and zoning produces a clean, combustible gas that can be burned in the combustion tube and chamber for drying applications or in a radiant section of a boiler. The gasification rate is controlled by the demand of the dryer and boiler.

The hydrocarbons contained in the gasses are thermally cracked and burned in the combustion tube and chamber. The resulting clean hot air can be cooled and blended with recirculating air to maintain the desired temperature in drying applications or directed to a boiler for final combustion. The duct system will include an emergency vent stack to safely exhaust gas to the atmosphere in the event of a failure of the induced draft fan.

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WESTERN · REGIONAL
BIOMASS
ENERGY · PROGRAM

P O Box 95085, 1111 "O" Street, Suite 223, Lincoln, NE 68509
Phone 402-471-2867 Fax 402-471-3064 Email jgraef@mail.state.ne.us
Web Site www.westbioenergy.org

News Release
For Immediate Release
April 10, 1998

For More Information Contact
Jeff Graef, Jerry Loos
(See Media Note at End of Release)

**19 Biomass Energy Projects in
California, Colorado, Kansas, North Dakota, Nebraska, New Mexico,
Nevada, Oklahoma, Texas and Wyoming to Share $947,530**

Lincoln, NE – The 13-state Western Regional Biomass Energy Program picked 19 biomass-to-energy projects in 10 states totaling nearly $1 million for possible funding. Western is one of five regional biomass energy programs funded by the U.S. Department of Energy designed to further the goal of replacing fossil fuels with renewable energy resources to generate electricity and power vehicles. Negotiations To Begin "Projects were selected on technical merit," Jeff Graef, Western administrator said. "Over the next few months, Western staff will contact grant winners to finalize project details such as cost and completion dates." The 19 Winners The 19 projects selected by Western's advisory panel allocated $947,530 for the projects. Those projects anticipate adding at least $2.138 million in funds from other sources. Western requires the winners to at least match the grants dollar-for-dollar. The particulars on each of the projects selected:

CALIFORNIA

· Colusa County, CA; Fife Environmental
Grant of $48,400; Matching funds of $48,400
This project will explore disposal/energy production options for rice straw not that field burning is being substantially reduced. The project will design an economical and commercially effective collection, storage and delivery system for rice straw. It is estimated the 400,000 tons of rice straw produced locally could produce 50 megawatts of electricity or 2.4 million gallons of ethanol annually.
Contract Les Fife, phone 916-668-1559

· Durham, CA; Langerwerf Dairy
Grant of $23,342; Matching funds of $23,342
This project will evaluate and refurbish a 16-year-old waste processing system used on a 400-cow dairy. The system biochemically converts solid wastes to methane gas and other by-products. No assessments on a system this old have ever been conducted.
Contact Leo Langerwerf, phone 530-893-3131

· Fountain Valley, CA; Cyclus Envirosystems
Grant of $69,945; Matching funds of $570,785
Under this project, the grant winner and the Orange County Sanitation District will design, build and test a 3,600 gallon/day plant that will biochemically convert organic landfill wastes and sewage sludge to methane gas which can be sold to produce electricity. The test of this process will last for one year.
Contact Dennis Burke, phone 360-923-2000

· Valencia, CA; Appel Consultants
Grant of $30,000; Matching funds of $30,000
This project will augment efforts funded from other sources to document design and performance

information as well as lessons learned, fuel handling, ash disposition and pollution controls on 20 existing biomass-fired power plants within the region.
Contact George Wiltsee; phone 805-253-3492

COLORADO

· **Denver, CO; City & County of Denver**
Grant of $48,000: Matching funds of $81,050 City and county government in Denver will determine the feasibility of constructing, financing and operating a publicly-accessible alternate fueling stations with five different fuels –ethanol, compressed natural gass, propane, liquified natural gas and electricity. This station, if built, would be likely the first of its type in the nation.
Contact Deborah Kielian; phone 303-285-4064

KANSAS

· **Manhattan, KS; Kansas State University**
Grant of $75,000; Matching funds of $124,474
This project will assess how swithgrass production costs can be reduced, sales of the feedstock maximized and which electricity and heat markets may be interested these energy sources. The ability of switchgrass to reduce rervoir sedimentation while improving water quality and production yields will be assessed. The feasibility of water quality support payments to growers and growing switchgrass on Conservation Reserve Program land will also be evaluated.
Contact Richard Nelson; phone 785-532-4999

NEBRASKA

· **Lincoln, NE; Nebraska Soybean Board**
Grant of $8,806; Matching funds of $15,619
Demonstrate .25% Biodiesel Heavy Trucks This one-year project would expand the use of soybean and diesel fuel blend in all the medium and heavy-duty trucks operated by the Nebraska Department of Roads. An earlier use of soybean-enhanced fuels was limited to several sites in eastern Nebraska. Under this effort, one-quarter of one-percent of each gallon of diesel used by the state agency will contain soybean oil.
Contact Victor Bohuslavsky; phone 402-441-3140

· **Lincoln, NE; University of Nebraska**
Grant of $20,000; Matching funds of $90,440
This grant will provide a portion of the financing for the University's 85 percent ethanol entry in the 1998 Ethanol Vehicle Challenge. This college-level competition pits mechanical engineering students from 20 schools in a test to improve the operating and fuel efficiency of a vehicle that runs on a higher percentage blend of ethanol and gasoline.
Contact William Wiens; phone 402-472-3088

· **Nebraska City, NE; National Arbor Day Foundation**
Grant of $58,734; Matching funds of $71,368
The existing fuelwood energy plant visitors' center will be modified to allow viewing of the inner workings of the Lied Center's heating/cooling operations that are fueled by wood. An interpretive exhibit and other exhibit materials will also be developed for use in the visitor's gallery.
Contact John Rosenow; phone 402-474-5655

· **York, NE; High Plains Corp (Bryan & Bryan)**
Grant of $75,000; Matching funds of $221,500
This project will examine the feasibility of using methane gas produced from ethanol waste water to power a fuel cell that generates electricity and heat that can be used by the ethanol plant. If successful, this would be the first use of a fuel cell utilizing biological waste from and ethanol plant, rather than processing the waste through sewage systems.
Contact Randy Sigle; phone 402-362-2285

NEVADA

·**South Lake Tahoe, NV; Nevada Tahoe Conservation District**

Grant of $74,963; Matching funds of $151,240
A group of local organizations will attempt to utilize forest waste being removed from the Lake Tahoe region to produce electricity at a power plant in Loyalton, CA. Sierra Pacific Power Company would then sell the power to others as electricity produced from renewable resources or "green power". Contact Suzanne Pearce; phone 916-541-5654

NEW MEXICO

· **Albuquerque, NM; Thermogenics**
Grant of $72,340; Matching funds of $91,427
This project will partially finance engineering design changes in technology that produces liquid alcohol fuel by converting to gas various wastes that are traditionally landfilled. The alcohol fuel, called Ecalene, can be used as both an oxygenate additive for gasoline and as an alternate fuel. If the project succeeds, a 30,000 gallon a day production plant could be built on Colorado's Front Range. Contact Stephen Brand; phone 505-344-4846

NORTH DAKOTA

· **Grand Forks, MD; University of North Dakota**
Grant of $25,000; Matching funds of $25,000
This project will examine the feasibility of usinig locally-grown aspen wood pulp and switchgrass planted on marginal farm land to replace agricultural grains in the production of ethanol. If successful, this project could lessen ethanol production costs at the state's two ethanol plants and expand the ethanol industry in the state.
Contact John Hendrikson; phone 701-777-5215

OKLAHOMA

· **Tulsa, OK; Primenergy, Inc.**
Grant of $75,000; Matching funds of $79,100 This project will utilize an existing facility that converts biomass feedstock into gases in Tulsa to perform additional tests on a variety of feedstock materials. These tests will also find ways to remove contaminants from the gases so that the gases can fuel turbines and engines.
Contact Kevin McQuigg; phone 918-835-1011

· **Stillwater, OK; Oklahoma State University**
Grant of $75,000; Matching funds of $220,093
Using wheat straw or switchgrass to replace corn and milo in the production of ethanol requires resolving a number of issues; finding the best way to grow, harvest, transport, store and process the new feedstock. As research progresses, new questions related to plant design, economics and environmental issues arise as larger sized tests are conducted. This project will attempt to resolve these issues.
Contact C.B. Browing; phone 405-744-9694

TEXAS

· **Tahoka, TX; Cratach**
Grant of $50,000; Matching funds of $182,820
This project builds on earlier research of biomass-to-electricity power plants. Using straw, grass, nut shells, and cotton gen trash as fuel, this project will complete the development and test of a one megawatt unit in Tahoka. If successful, power plants such as these could be located at sugar, rice, wood and textile mills, coffee plantations and electricity for use by the plants and mills.
Contact Joe Craig; phone 806-327-5220

· **Canyon, TX; West Texas A&M University**
Grant of $66,200; Matching funds of $67,915
An estimated 36 billion pounds of cattle manure is produced annually in the Texas Panhandle. The project at the University's state-of-the-art feedlot will explore practical solutions for resolving this waste problem while extracting the waste's energy potential. In both laboratory and pilot level tests, manure will be placed in membrane-lined and covered landfill cells. The biogas produced from these tests will be analyzed for content and production.
Contact David Parker; phone 806-651-2563

· **Austin, TX; Texas Renewable Energy Industries Association**
Grant of $29,000; Matching funds of $20,850
This grant will finance three seminars in 1998 and 1999 on livestock waste-to-electricity, methane gas potential and production from landfills and renewable transportation fuels such as biodiesel and ethanol.
Contact Russell Smith; phone 812-345-5446

WYOMING
· **Yellowstone National Park, WY/MT; University of Denver**
Grant of $22,880; Matching funds of $22,800
This project will monitor pollution from snowmobiles in Yellowstone Park. Emissions from National Park Service snowmobiles using ethanol fuel blends and lube oil produced from soybeans and tallow will be compared with those operating on traditional fuels. The results will be made available to the public as well as area snowmobile operators and park officials.
Contact Donald Stedman; phone 303-871-2580

Grants from Western to the winners are estimated to total $947,530. The winners have pledged $2,138,223 in cash and inkind matching funds for the projects.

$4.8 Million Requested
According to sources at Western, 83 project applications for a record-shattering $4.8 million were submitted in January for funding. "Even if the entire regional biomass budget was available for these 82 projects, we would still be $1.8 million short," Graef said. Only $3 million is being shared this year by all five regional biomass programs.

Biomass proposals submitted involved projects in 12 of the 13 states in the region. South Dakota was the only state in which no projects and even projects outside the 13-state region were submitted for possible funding by Western.

Making the Hard Decisions
Each of the 82 proposals was reviewed four times. The proposals were checked for completeness, evaluated by experts in the project area, ranked by the representatives from the 13-member states and checked by the U.S. Department of Energy for diversity and geographic balance.

The Nebraska Energy Office in Lincoln provides day-to-day operations for Western. The U.S. Department of Energy's Denver Regional Support Office provides management oversight.

Note to the Media: For information on specific projects, please direct inquiries to the individual listed as the contact under each project.

March 30, 1998

Contact: (918) 835-1011
W.N. (Bill) Scott, President
Kevin McQuigg, Vice President, Process Engineering

FOR IMMEDIATE RELEASE

GASIFICATION TEST RUN APRIL 1, 1998

**BIOMASS ENERGY CONVERSION SYSTEM ENGINE TEST
GENERATES ENOUGH ELECTRICITY TO LIGHT 300 HOMES**

Tulsa, Ok March 30, 1998 - Primenergy, Inc. will conduct an engine test at its Tulsa test facility, located at 3172 N. Toledo, on Wednesday, April 1 at 10:00 a.m. During this test, rice hulls will be used as a biomass fuel to power an internal combustion engine connected to an electrical generator. The amount of electricity produced during one hour of the test would power 300 homes or an average household for two weeks.

The Primenergy gasification system uses a staged combustion process to convert 600 lbs. of rice hulls per hour into a combustible biogas while not contributing to the greenhouse effect. Primenergy systems up to eight times larger thatn the test system are currently in use by rice producers in Arkansas and Mississippi. The gasification systems are currently being marketed world wide.

An application of the technology has also been proposed as an alternative to land application of poultry litter. Primenergy representative Kevin McQuigg spoke about the company's technology to government and industry representatives at the Coalition of Northeastern Governors' (CONEG) March 26 meeting held in Washington, D.C. The purpose of the meeting was to discuss solutions to the concern about deterioration of the water quality in the Chesapeake region.

Nutrient run-off and water pollution from land application of poultry litter are issues that must be addressed as land application may no longer be allowed in the Chesapeake region within two years. CONEG is hoping this meeting will facilitate the location of additional private and public funding to test alternative methods of disposal. Mr. McQuigg says that Primenergy will be part of the additional test and expects further word on the funding in the next 60 days.

Much like eastern Oklahoma and western Arkansas, the Delaware, Maryland and Virginia areas (Delmarva) have a large concentration of poultry farms. Primenergy has proposed the energy conversion alternative to large chicken integrators in the Oklahoma/Arkansas area.

Kevin McQuigg or Bill Scott would be happy to discuss Primenergy's gasification system, the CONEG conference or arrange for you to attend the engine test.

Return to Primenergy's Hot News

LARGE GASIFICATION SYSTEMS

This table shows companies and conglomerates working on large gasifier systems. These groups often go through a sequence of names, so if you don't see the group you want, search the table using control+F to find key names or words.

- SMALL GASIFIERS
- GASIFIER RESEARCH AND SUPPORT
- GASIFIER EQUIPMENT AND CONSULTANTS
- DATABASE HOME PAGE
- HOME PAGE
- CONTENTS

LARGE GAS

ORGANIZATION	PURPOSE/DESCRIPTION	COUNTRY	CONTACT	PHONE/FAX	E-MAIL	WWW.PA
AERIMPIANTI (Ansaldo, TPS)	Fuel gas for cement kiln or power, 2 Circulating TPS FBs	ITALY	G. Campagnola	39 2 54 97241 39 2 54 97300		
FOSTER WHEELER (Formerly Ahlstrom, AB)	Circulating Atmospheric & Presssurized FBs for power	FINLAND	Ragnar Lundqvist	358 5229 3314 358 5229 3309		
BIOELECTRICA	Demonstration of short rotation forestry, using Lurgi CFB gasifierIGCC	ITALY	Costantino Panzani	-- 39 399 50 53 50 21		
VARNAMO IGCC PLANT, SYDKRAFT (Sydkraft, Foster Wheeler)	IGCC, recirculating pressurized fluid bed for First biomass IGCC pressurized fluid bed plant	SWEDEN	Krister Stahl	46 40 25 59 63 46 40 611 5184		
BIOMASS GASIFICATION FACILITY (BGF) (Westinghouse, PICHTR/IGT, US DOE)	Pressurized Bubbling FB, Renugas Process, for IGCC	USA	Ben Wiant	808 579 8020 808 579 9812	bgfmaui@maui.net	
BIOSYN	Oxygen gasifier for methanol production	CANADA	Prof. Esteban Chornet	819 821 7171 819 821 7955		
BURLINGTON ELECTRIC, VERMONT (FERCO, Battelle)	IGCC Demonstration of Battelle gasifier at existing wood plant	USA	John Irving	802 865 7482 802 865 7481	jirving104@aol.com	
CARBONA (Formerly Tampella, Enviropower, and Vattenfall)	Pressurized Fluidized Bed	USA	Kari Rasanen	358 93 358 0300 358 93 358 0325		
ELSAM/ELKRAFT	Fluidized Bed for Biocycle project	DENMARK	Michael Madsen	45 44 66 00 22 45 42 65 61 04		
IMTRAN VOIMA	Combined cycle	FINLAND	S. Hulkkonen	358 9 8561	weppo.hulkkonen@ivo.fi	

	powerprocess using steam drying, injection			4612 358 9 563 2225		
JWP ENERGY PRODUCTS (Formerly Energy Products of Idaho, EPI)	Steam, power Fluidized Bed	USA	Michael L. Murphy	208 765 1611 208 765 0503	EPI@EnergyProducts.com	
KVAERNER ENVIROPOWER INC.		USA	Herbert. J. Fruth	410 356 1111		
LURGI UMWELTTECHNIK GMBH	Circulating Fluid Bed Gasifier for power generation, cement or lime kilns	GERMANY	J. Albrecht (J. L	49 69 5808 3530 49 69 5808 2628		
NEW ENGLAND POWER SERVICE		USA	Raymond L. Coxe	508 366 9011X 3120		
POWER GASIFIERS INTERNATIONAL	Complete gasificaiton systems, 40-5000kW	UK	Nigel Viney	44 767 680 351 44 767 683 298		
POWER SOURCES, INC.	Owner operator of Various commercial gasifiers for steam, hot air, power	USA	Dennis C. Williams	704 525 5819 704 527 1218	powersou@aol.com	
PRODUCERS RICE MILLS ENERGY SYSTEMS	Multi zone, fixed grate, gasifier for process heat, steam, power.	USA	Ron Bailey Jr.,	501 767 2100 501 767 6968	prmesron@mail.snider.net	
PROLER INTERNATIONAL	Reforming HC waste to syngas	USA	Dennis Caputo, VP	713 627 3737 713 627 2737		
PUROX	Fixed bed updraft slagging gasifier for disposal of MSW, steam, syngas	USA	Hiroshi Tamura	415 345 1338		
SKYGAS VENTURESEARCH (Unitel)	Electric Arc Fixed Bed Gasifier for Syn-gas, methanol	USA	Ravi Randhava, Serge Randhava	847 297 2265 847 297 1365		
SOFRESID/CALIQUA (Andco Torrax, Ascab-Stein)	Slagging updraft air gasifier	FRANCE	M. J. Vigouroux	33 1 48 70 4692 33 1 48 70 4444		
SUR-LITE CORP.	Fluidized Bed for Gas, Steam	USA	Edward G. Gjerde	562 693 0796 562 693 7564	sur-lite@deltanet.com	
TAMPELLA POWER INC. (TPS)(Enviropower;	Recirculating Fluidized Bed Gasification	FINLAND		358 90 4354 2089 358 90 4354		

IGT)				2089		
TERAMETH INDUSTRIES (TMI)	Landfill gas reforming to methanol, DME H2, CO2	USA	Gil Cervantez	510 939 2020 510 939 2052		
THERMOCHEM (MTCI)	Pulse combustor steam fluidized bed	USA	K. Durai-Swamy	310 941 2375 310 946 0895		
THERMOSELECT, SA	Solid waste treatment; high temperature oxygen gasifier, turnkey plant	USA	David Runyon	248 689 3060 248 689 2878		
TPS TERMISKA PROCESSOR, AB (Formerly Studsvik, see Greve, BIG-CC, ARBRE)	Major CFB gasifier manufacturer for IGCC, Greve plant in Chianti, IT, IGCC Brazil, UK	SWEDEN	Eric Rensfelt	46 155 22 13 00 46 155 26 30 52	tps@tps.se	
UHDE GMBH	Gasification of biomass, ceogeneration.	GERMANY	Jochen Keller	49 231 547 2335 49 231 547 3032		
WELLMAN PROCESS ENGINEERING	Updraft Fixed Bed Gasifier for generation of fuel & process gas from solid fuel	UK	Richard McLellan	44 121 565 2766 44 121 555 5651		
BRIGHTSTAR SYNFUELS CO.	Externally heated, steam reforming of biomass, for medium Btu syngas	USA	Ron Menville	504 642 2500 504 642 2503	ronmenvillejr@worldnet.att.net	
BIG-GT (State Bahia, Brazil, Electro-Braz, Shell, World Bank)	Biomass Integrated Gasification with combined cycle to prove commercial viability of atmospheric BIG-CC	BRAZIL	Eduardo Carpentieri	55 81 228 2605 55 81 227 2785	carpent@elogica.com.br	
ARBRE (TPS)	8MW CFB demonstration of IGCC & Short rotation forestry	UK	Keith Pitcher	? 44 113 224 42384		
HURST BOILER CO.	Underfed stoker gasifier-combustor for Heat, power, steam	USA	Gene Zebley	912 346 3545 912 346 3874	hboiler@rose.net	
GLOBAL ENERGY	Combining Coal, MSW	USA		513 621		

(AFT-IGCC)	IGCC for clean power			0077 513 621 5947		
COMBUSTION CONSULTANTS LTD	Fixed bed close coupled gasifiers to supply clean combustion gas at over 2,000 F	NEW ZEALAND	Paul D. Williams	64-6 875 0734 64-6 875 0098	waterwide2xtra.co.nz	
ASSIDOMN KRAFTLINER	94186 Pitea	SWEDEN	Gunnar Lundkvist		Gunnar.lundkvist@asdo.se	
FERCO (Future Energy Resources Corp.)	Developers of large gasifier systems for efficient power (Burlington, Binaga)	USA	Sim Weeks	404 831 9355 404 814 0549		www.future-ene
PRIMENERGY, INC	Multi zone, fixed grate, co-current gasifierGASIFIER SYSTEMS-LARGE systems for heat/power,	USA	W. N. (Bill) Scott	918 835 1011 918 835 1058		www.primenerg

PROGAS - a new programme on gasification and pyrolysis technology launched by VTT Energy

The publicly funded gasification and pyrolysis research activities of VTT have been integrated to a three-year programme to elevate the profile of Finnish gasification and pyrolysis R&D and to efficiently maintain contacts with foreign enterprises that utilise these technologies. *Esa Kurkela*, co-ordinator of the programme, tells that the programme will focus on applied technical research, and on process and equipment development to be done in co-operation with industries. The total volume of the programme in 1997 will amount to FIM 12.2 million, the main financers being VTT, EU Joule Programme, Technology Development Centre Finland (TEKES) and a number of enterprises. In 1997, part of PROGAS projects are also included in the BIOENERGIA and LIEKKI Programmes that will be finalised in the near future.

AIMS

PROGAS Programme aims at promoting development and commercialisation of energy production methods based on gasification and pyrolysis technology as well as new export products. The processes concerned will be more efficient, environmentally sounder and, in the long term, also more profitable than the competing conventional combustion technology. This aim will be achieved through the following technical sub-tasks:

- supporting the Värnamo biomass-IGCC plant and other demonstration projects on pressurised gasification by follow-up studies, test runs and solving critical problems,
- improving the competitiveness of IGCC plants by developing gasification of coal and biomass mixtures, hot gas cleaning and other critical parts of the process,
- supporting demonstration projects of atmospheric-pressure gasification, and solving critical problems that are hampering the commercialisation of the gasification systems for problematic agrobiomasses and wastes,
- development and demonstration of power plant concepts based on flash pyrolysis and diesel engines, and assessment of their technical operability and competitiveness,
- development of catalytic tar cleanup, presently being the bottleneck of the gasification diesel power plant, and assessment of the competitiveness of the new technology,
- active development of new conversion methods and process ideas for solid fuels and initiation of new research and development projects.

PRODUCT LINES AND POTENTIAL

We strive towards the goals of the programme by applied research, industrial development projects and follow-up projects of demonstration plants, grouped into four product lines: 1) Pressurised gasification processes, 2) Atmospheric-pressure gasification for boiler use, 3) Smal-scale power plants based on diesel engines and pyrolysis or gasification technology, and 4) Novel applications.

A rough estimate about the size of the market for the main products of the programme was prepared at the preparatory stage of the Progas programme. The short-term assessment is based mainly on known demonstration projects. The long-term estimate has been prepared conservatively supposing that only 5 - 10 % of the biomass-electricity potential of the Existing Policies Scenario would be based on the new technologies to be developed within the programme. If the gasification technology will be commercialised at a competitive price sooner than expected and if investments in renewable energy sources will grow, the 25-year potential may be significantly higher than assessed.

Product line	Potential, < 5 years		Potential, < 25 years	
	Number of plants	Total, million FIM	Number of plants	Total, million FIM
Simplified IGCC	2	1 000	100	40 000
Atmospheric-pressure gasification for boiler use	10	500	100	5 000
Small-scale gasification/ pyrolysis power stations	5	250	300	15 000
Total	17	1 750	500	60 000

KEY ENTERPRISES

- Foster Wheeler Energia Oy, Carbona Oy, Imatran Voima Oy, Condens Oy, Finland
- Wartsila Diesel, Vapo Oy, Neste Oy, Finland
- Sydkraft, Sweden, Elkraft, Denmark, N.V EPZ, the Netherlands, BASF, Germany

For further information, contact: Esa Kurkela, VTT Energy, P.O. Box 1601, FIN-02044 VTT, Espoo
Tel: +358 9 456 5596, fax: +358-9-460 493

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General Information

New Energy Technologies

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Technical Services

Waste to Energy

Kai Sipilä
Research Manager

Research topics:

Gasification and Gas Cleaning
Pressurized gasification and critical technical issues of simplified gasification combined-cycle processes
Atmospheric-pressure gasification for small-scale energy production and for co-combustion in large utility boilers
Fuel characterization and fundamentals of gasification and hot gas cleaning

Pulp and Energy
Pyrolysis oil production from biomass: improvement of product quality and reduction of product cost
Recovery of pulping chemicals, black liquor combustion, alternative conversion processes

Waste to Energy
Source separation, handling, co-combustion and gasification of solid wastes, optimisation of waste-to-energy systems

VTT EnergyNew Energy Technologies
P.O.Box 1601
FIN-02044 VTT, Finland

Tel. +358-9-4561
Fax +358-9-460493

last update 29.1.1998
Sinikka.Soirinsuo@vtt.fi

Cost and Performance Analysis of Three Integrated Biomass Gasification Combined Cycle Power Systems

Kevin R. Craig and Margaret K. Mann
National Renewable Energy Laboratory
Golden, CO 80401

Introduction

Currently, there are approximately 8.5 GW of grid-connected biomass electrical generating capacity in the U.S., including that from landfill gas and municipal solid waste (see Figure 1). Unfortunately, a substantial fraction of this existing capacity employs relatively unsophisticated and inefficient direct steam technology. Average efficiencies for existing systems are less than 25%. As a consequence, the size of a given biomass power installation historically has been limited by these low efficiencies and the amount of fuel within an economical transportation radius. The resulting low output yields a high capital cost for these systems on a dollars per kilowatt basis ($/kW). A number of recent developments are changing the nature and constraints of the biomass power option, however.

Significant technical advancements are being made that will allow for substantially increased utilization efficiency of biomass as a fuel. Advanced gas turbine and combined cycle technology is being commercially deployed and demonstrated with natural gas as well as solid fuels such as coal through the use of gasification technology. Biomass gasification technologies are also being developed and demonstrated. Linking these conversion and utilization processes will nearly double current biomass electrical generation efficiencies. Concurrently, DOE, NREL, and ORNL are actively pursuing development and demonstration of Dedicated Feedstock Supply Systems (DFSS). Such systems would allow operation of plants requiring as much as 2000 dry T/day of biomass feed. The combination of advancing technology and improved fuel supply will increase the feasible biomass power plant size into a range attractive to utilities, and thus expand the market for biomass power beyond the independent power producers and co-generators who have, to date, been the principal players in the biomass power industry.

Moreover, these biomass power systems will further leverage research dollars by directly and substantially benefitting from the technological advances being made by government and industry funded gas turbine and fuel cell development programs. These utilization technologies are the subject of substantial development efforts, and are being demonstrated in integrated systems with coal gasifiers under the Clean Coal Technology Program.

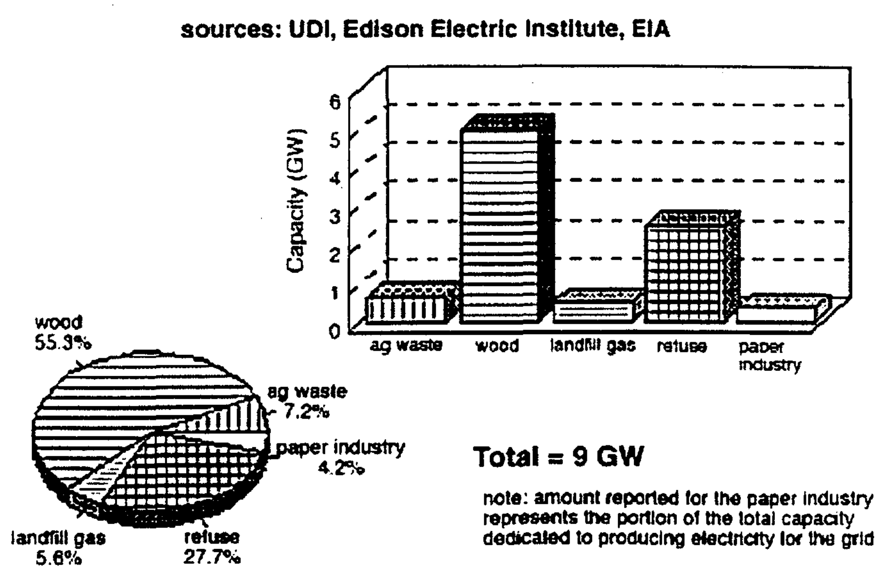

Figure 1. Grid Connected Electricity from Renewables

Purpose of Study

The purpose of this study was to determine the efficiency and cost of electricity of IGCC systems incorporating biomass gasification technology. The systems we examined incorporate state-of-the-art, commercially available aero-derivative and utility gas turbine technology as well as scale-appropriate modern steam cycle technology. The resulting performance and cost numbers indicate the commercial potential for these systems, and define areas for continued and focused research. We also examined different options for gas cleaning prior to combustion in the gas turbine combustor, and compared our results to previous studies on this subject.

Systems Studied

ASPEN simulations were performed on three biomass IGCC systems: an air-blown (i.e. direct-fired) pressurized fluidized bed gasifier of the type under development by the Institute of Gas Technology (IGT), the Battelle Columbus Laboratory (BCL) low pressure indirectly-heated biomass gasifier, and an air-blown low pressure gasifier similar to that developed by Thermiska Processor AB (TPS) in cooperation with ABB-Flakt. Process development unit (PDU) experimental results, where available, provided the basis for gasifier performance predictions. A high degree of process integration between the gasifier and combined cycle was incorporated to maximize system efficiency. The combined cycles investigated were based on aero-derivative and state-of-the-art utility gas turbines of appropriate sizes. To make a direct comparison of different combined cycle systems, the high pressure direct-fired gasifier was integrated with both an aero-derivative gas turbine and an utility gas turbine. The aero-derivative gas turbine selected for this study was the General Electric LM5000PC. This unit has a higher pressure ratio (24.8) and firing temperature (in excess of 1150°C) than the utility machines selected for most previous biomass IGCC studies. The utility-scale gas turbine selected was the GE MS-6101FA, an advanced turbine that moves GE's "F" technology (high firing temperature, high efficiency) down to a 70 MW-class machine.

Because of lower overall system efficiencies (as compared with the utility turbine case) and higher fuel pressures required, cases integrating the low pressure gasifiers with the LM5000 turbine were not considered. All systems employing the utility turbine used a two-pressure reheat steam cycle. The LM5000 case used a small, non-reheat steam cycle. Gas cleanup in all cases included a tar cracker to reduce the quantity of higher hydrocarbon species in the gas, followed by gas cooling via direct or indirect quench to condense alkali species. For the high pressure gasifier, a hot ceramic candle filter of the type being offered by Westinghouse and being demonstrated under the Clean Coal Technology Program was used to remove particulate matter including these condensed alkali compounds. In this case, the quench step cooled the gas down to less than 538°C. Particulate removal in the low-pressure gasifier cases was accomplished with cyclones and a fabric filter. The direct quench that follows in these latter cases reduces the fuel gas temperature to 96°C in preparation for compression.

Other alternate designs that were studied include greenfield plant construction instead of an existing plant site basis, indirect cooling of the synthesis gas, various levels of humidification of the syngas, and different moisture levels of the feedstock. It should be noted that not all of these variations were examined with each gasifier combined cycle system. Performance, cost, and economic data were developed for each of the cases tested, and are presented in this report.

Methodology

The intent of this study was to evaluate the ultimate potential for application of IGCC technology to biomass-based power systems of large scale (> 30 MWE). Therefore, the plant designs examined were assumed to be for mature, "nth-plant" systems. The aggressive sparing and redundancies typically utilized for "first-plant" designs and the attendant cost associated with such an approach were not applied to the systems examined here. However, the technology and equipment utilized in all of the system designs is currently, though not in all cases commercially, available. In some cases, the technology selected for these systems is under development for increased reliability, availability, and maintainability. However, projected technological advances that may result from on-going research were not included or assumed.

The base year of 1990 was chosen for cost and economic analyses in this study. In part, this reference year was chosen to facilitate comparison of our costs with previous studies in this area.

Process Analysis

Detailed process models were developed using the Advanced System for Process ENgineering (ASPEN/SP) process simulator to evaluate the performance of the three biomass IGCC systems. The material and energy balance results of these simulations were used to size and cost major pieces of equipment from which the resulting cost of electricity was calculated. As part of this development, data from PDU operation of the IGT and BCL gasifiers were regressed and incorporated into a user-specified yield reactor. Detailed information on gasifier operation and performance at a variety of conditions was not available for the low-pressure direct gasifier. Therefore, this case utilized a quasi-equilibrium model and reactant ratios developed from limited data contained in a Lurgi report on fluidized bed gasification of biomass[1].

Gas turbine performance when utilizing low energy content biomass derived fuel gas was estimated based on the operating parameters (air flow, pressure ratio, firing temperature, outlet temperature) of the selected gas turbine[2], [3]. A simulation was developed that matches its performance (output, heat rate) on natural gas fuel by "tuning" the efficiency of the various compression and expansion stages as well adjusting heat losses, cooling air extraction etc. Utilizing these same "tuning" parameters, the resulting turbine model was incorporated, along with the biomass gasifier and cleanup section models, into an overall gasification combined cycle simulation. The simulation was configured such that the amount of biomass fed to the system was calculated based on the amount of gaseous fuel required by the gas turbine to achieve its design firing temperature. Changes in the gas turbine output and efficiency because of the increased mass flow of the low energy content gas and the higher fuel gas temperature are thus roughly predicted. This approach has been employed in numerous studies performed at the Morgantown Energy Technology Center (METC) for coal-based IGCC systems. This prediction method has also been validated, within certain limits, by results obtained by turbine manufacturers and engineering firms that have prepared detailed designs of the such systems. It must be realized, especially in the air-blown gasifier cases, that modification of the gas turbine combustor may be required in order to efficiently combust the low calorific value fuel gas produced. The design limits of the turbine compressor must also be kept in mind when mass flow through the turbine section is increased. Such a scenario arises, again, due to the reduced (compared to natural gas) chemical energy content of the fuel gas produced from biomass.

The simulation calculates the overall biomass-to-electricity efficiency for the system based on total feed to the system and the net electrical power produced. The major auxiliary equipment items (feed water pumps, boost compressor, blowers, etc.) are explicitly included in the simulation, and their power requirements subtracted from the gross plant output. A 3% charge was taken against this preliminary net power (gross minus major equipment) to account for balance of plant electrical power including wood handling and drying.

Site Conditions

Since this was not a site specific design, ranges of ambient conditions were not available. Therefore, International Standards Organization (ISO) conditions (15°C, 1 bar atmospheric pressure, 60% relative humidity) were assumed as the ambient conditions for this evaluation. Air fed to the plant was assumed to be composed of 20.73 mol% oxygen, 78.22 mol% nitrogen, 1.02 mol% water, and 0.03 mol% carbon dioxide.

Wood Analysis

The biomass used in each analysis was that used most extensively in testing each gasifier. Wisconsin maple wood chips have been tested at a number of gasifier conditions in the IGT RENUGAS® 9 T/day process development unit (PDU), and are therefore used in the high pressure simulations. According to tests at BCL, the biomass used for the low pressure indirectly-heated gasifier simulation is typical of woody biomass such as hybrid poplar. Wisconsin maple was also used as the feedstock in the low pressure direct gasifier simulation. The ability to feed biomass to gasification systems, high and low pressure, has been demonstrated in experimental work at a variety of scales. Detailed analyses of the feedstock, product gas, and solid residues are available from experimental data for the IGT and BCL gasifiers. For the low-pressure direct gasifier case, feed data is available and char and product gas composition is estimated. In the ASPEN simulations, biomass and char were simulated as non-conventional components; the elemental and property analysis for each biomass type are shown in Table 1. The heat of combustion was calculated by adjusting the standard ASTM correlation for biomass.

General Plant Requirements

With the exception of the greenfield analysis of the high pressure direct gasifier, the plants examined are assumed to be located at or near an existing generating facility and to share facilities such as land and an electrical substation. Additionally, all plants are assumed to be in close proximity to roads or railroad spurs adequate for delivery of the biomass feedstock. This is likely to be true when a dedicated feedstock supply system (DFSS) is employed since the power plant would be sited near the center of the agricultural area representing its biomass "shed". In addition to the major process areas and equipment discussed later in the report, the following items and systems are assumed to be part of the plants evaluated in this study: cooling water systems, plant and instrument air, potable and utility water, effluent water treatment, flare system, fire-water system, interconnecting piping, buildings, lighting, computer control system, and electrical system.

Table 1: Biomass Analysis

	Wisconsin Maple	Hybrid Poplar
Ultimate Analysis (weight %, dry basis)		
Carbon	49.54	50.88
Oxygen (by difference)	43.73	41.90
Hydrogen	6.11	6.04
Nitrogen	0.10	0.17
Sulfur	0.02	0.09
Chlorine	0.00	0.00
Ash	0.50	0.92
Heat of combustion, HHV, Btu/lb, dry basis	8,476	8,722
Moisture, as received	38%	50%

Process Descriptions

Description of Plant Sub-sections

The biomass-based IGCC electric generating plants considered in this study consist of the following process sections:

- Fuel receiving, sizing, preparation, and drying
    - Truck unloading system
    - Wood yard and storage
    - Sizing and conveying system
    - Dryers
    - Live storage area
- Gasification and gas cleaning (Gasification Island)
    - Wood feeding unit
    - Gasifier
    - Char combustion and air heating
    - Primary cyclone
    - Tar cracker

  - Gas quench
  - Particulate removal operation

- Power Island
  - Gas turbine and generator
  - Heat Recovery Steam Generator (HRSG)
  - Steam turbine and generator
  - Condenser, cooling tower, feed water and blowdown treating unit

- General plant utilities and facilities

All systems simulated incorporate a fairly high level of integration between plant sections. In each system examined, a char combustor is used to convert any un-gasified carbon. The resulting energy provides pre-heating for the gasifier steam and air (where required), as well as heat for the biomass drying. In actual practice, carbon conversion in the direct gasifiers may be sufficiently high that a separate char combustor is not required. In the indirectly-heated gasification system, the char is combusted to heat sand which is circulated to the gasifier. There, the hot sand provides heat for the endothermic gasification reactions.

Air for the direct-fired gasifiers was removed from the gas turbine compressor discharge scroll and boosted or let down in pressure, as appropriate, with a compressor or turbine. This air extraction is necessary to avoid significantly increased mass flow in the expansion section of the gas turbine, and thus compressor surge. Without air extraction, turbine mass flow would be increased due to high fuel gas flows necessitated by the fuel gas's low energy content. Gasification steam, where required, was extracted from an appropriate location in the steam cycle.

For the aero-derivative turbine (LM5000) cases, a single train for all process sections and units was used. The "small" utility turbine (MS-6101FA) case required use of two gasification trains to provide adequate fuel gas. This also imparts some part-load redundancy in these systems. Each plant section is discussed further below.

Wood Preparation and Drying

Design of the wood receiving, handling, and drying operations was based on a number of existing studies in this area [4], [5], [6]. Wood chips sized to 0 x 2" are delivered by truck to the plant site at a cost of $46/bone dry Tonne ($42/bone dry ton). The feed requirements for each plant are shown in Table 2. The wood was unloaded and moved to the paved storage yard that was sized to provide one week of feed storage. Wood reclaimed from the storage yard was sized to less than 1½" and conveyed to the wet feed storage silo (one day of storage). Wood from the silo was conveyed from the silo to the dryers (2 in parallel) and then to the "live" or "day" storage tank from which it is fed to the gasifier.

Table 2: Biomass Feed Requirements for Each Analysis

	Feed Requirements (dry T/day)
High pressure gasifier, aero-derivative gas turbine	712
High pressure gasifier, indirect quench	712
High pressure gasifier, greenfield plant	712
High pressure gasifier, advanced utility gas turbine	1,620
Low pressure indirectly-heated gasifier, utility gas turbine	1,486
Low pressure air-blown gasifier, utility gas turbine	1,352

The wood dryers are of the co-current rotary drum type. Design conditions selected for the wood drying section result in a moisture content of 11% by weight (17% in the low-pressure direct case for reasons that will be explained later). In the direct-fired gasifier plants, the gas used for wood drying was a mixture of combustion products from a small fluidized bed combustor flue gas extracted from the HRSG. For the indirectly-heated gasifier, a mixture of ambient air and char combustor flue gas is used. For each design, sufficient ambient air is mixed with the combustion products to reduce the gas temperature to 204°C (400°F) prior to introduction to the dryers. While this can result in a relatively high oxygen content (16 mole %), the temperature is believed to be sufficiently low to avoid the possibility of dryer fires. Gas leaving the dryers at a temperature of 80°C (175°F) enters the dryer cyclone and then a baghouse to reduce particulate emissions. The temperature level at the baghouse is, again, believed to be sufficiently low to mitigate fire danger. The dried wood exits the dryers at 68°C (155°F) and cools further during final transport to the feed system.

High Pressure, Air-Blown Gasification

The high pressure gasifier system selected for this study was a fluidized bed unit similar to that under development by the Institute of Gas Technology (IGT) and marketed under the name RENUGAS®. A schematic of this gasifier integrated with the combined cycle plant is shown in Figure 2. This is a pressurized, air-blown, single stage fluidized bed gasifier. The gasifier bed material is typically an inert solid such as alumina. The bed material improves fluidization quality and increases bed depth and heat capacity, solid residence time, and carbon conversion. The IGT gasifier has been operated over a wide range of temperature, pressure, oxidant, and fuel types at the process development (PDU) scale, and is the subject of a larger scale demonstration projects in the United States (Hawaii) and Europe (Finland).

Wood from the feed lockhopper is introduced into the pressurized feed hopper with live-bottom metering screws to meter the feed into an injection screw that introduces the feed into the gasifier near the bottom of the bed. Air and a small amount of steam are introduced to effect the gasification and combustion reactions. The operating temperature selected for the gasifier for this study was 830°C (1526°F). The gasifier operating pressure for aero-derivative turbine case was 3.24 MPa (32 atm) and 2.07 MPa (20 atm) for the utility gas turbine system. The former pressure is outside the currently demonstrated range for this gasifier which is 23 atm, but is believed to be achievable due to experience with coal gasifier designs operated at similar pressures. These pressures take into account the pressure drop through the gas cleaning systems and allow for a 25% pressure drop across the gas turbine fuel control valve. Gasifier design and operating conditions are contained in Table 3. Composition of the gasifier product gas was based on experimental data from the IGT PDU gasifier tests with maple wood chips. Continued development by IGT has lead to improved gas quality and increased carbon conversion since these data were obtained. It is expected that the commercial design for this gasification technology would realize these benefits as well. The product gas composition used in this study is contained in Table 4. Product gas from the gasifier enters the primary cyclone which removes char and ash particles prior to entering the tar cracking unit.

Direct quenching produces a fuel gas with a lower heating value (LHV) of 4.3 MJ/m3 (115 Btu/standard cubic foot). Indirect quench produces a fuel gas of slightly higher quality 4.8 MJ/m3 (128 Btu/standard cubic foot). Analysis indicates that indirect quenching is relatively cost neutral so could be used in cases where gas quality is important.

Table 3: High Pressure Gasifier Design Parameters and Operating Conditions

Gasifier temperature	830°C (1526°F)
Gasifier pressure	3.17/2.07 MPa (31.3/20 atm.)
Dried wood feed to gasifier	811 T/day (893 t/day)
Dried wood moisture content	11%
Gasifier internal diameter	2.86 m (9.4 ft.)
Solids throughput	6018 kg/hr-m2 (1,230 lb/hr-ft2)
Air / wood ratio (wt/wt, MAF)	1.07
Steam / wood ratio (wt/wt, MAF)	0.32

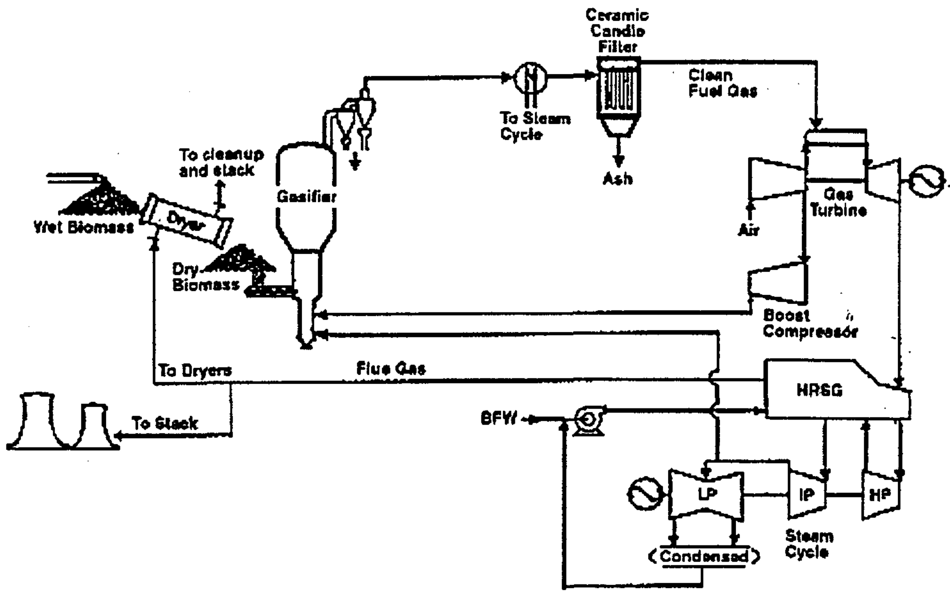

Figure 2. General High Pressure BIGCC Schematic

Gasifier Design

General gasifier size determination was based on information from the IGT 9 T/day PDU as well as the design for the scaled-up, 91 T/day unit operating at the Hawaiian Commercial and Sugar Company (HC&S) sugarmill at Paia, Maui, by the Pacific International Center for High Technology Research (PICHTR). Additional demonstrations of this technology include a 64 T/day unit in Finland. The solid throughput, gas superficial velocity, and the ratio of bed to disengaging zone cross-sectional area were all maintained at the same level as for the 91 T/day demonstration unit. This yielded a gasifier vessel with a bed diameter of 2.86 meters (9.4 feet) between the refractory lined walls and a vessel outside diameter of 4.26 meters (14 feet).

Table 4: High Pressure Gasifier Product Gas Composition

Component	Volume %
H2	8.91
CO	6.71
CO2	13.45
H2O	39.91
N2	24.18
CH4	6.51
C2H4	0.01
C6H6	0.07
Tars	0.16
H2S	0.005
NH3	0.06
LHV = 4.3 MJ/m3 (115 Btu/SCF)	

Gas Clean-up

For this case, gas cleanup was accomplished by cooling the product gas to less than 538°C (1000°F) via direct quench to condense alkali species. A hot ceramic candle filter of the type being offered by Westinghouse and being demonstrated in the Clean Coal Technology Program is then used for removal of particulate matter including, it is hoped, the condensed alkali compounds. Recent tests of tar cracking and this particulate and alkali removal strategy were conducted at the IGT PDU unit in Chicago. Results from these tests indicate that a tar cracker may not be necessary in an eventual commercial system design. The tars are produced in fairly small quantities, and appear to be substantially cracked prior to reaching the tar cracking vessel. The particulate filters tested at IGT also did not experience any plugging problems due to tars, and were successful in reducing the particulate matter and alkali species in the gas stream to very low levels. Long-term testing of the filters will be conducted in the coming year at the PICHTR facility. For the purposes of this study, therefore quenching followed by the ceramic candle filters was assumed to be sufficient for fuel gas cleaning.

High Temperature Gas Cooling

Alkali species present in the fuel gas can cause corrosion and deposition if introduced into the expansion section of a gas turbine. Therefore, it was necessary to remove these species prior to combustion. These must be removed to extremely low levels, typically less than one part per million. Fortunately, most alkali components present in biomass synthesis gas have relatively high condensation temperatures. Therefore, cooling to below 538°C (1000°F) results in condensation of the bulk of these species, usually as fine particles that can be removed with the rest of the particulates. This cooling can be accomplished in a number of ways. The base case analyzed here performs this cooling by direct injection of water into the gas stream. While this dilutes the fuel gas stream and reduces its heating value, it was the simplest and least expensive from an equipment standpoint. An alternate case utilized indirect cooling of the fuel gas, utilizing the recovered heat in the steam cycle.

High Temperature Particulate Removal

Westinghouse has been developing high temperature ceramic barrier filters for use in advanced IGCC and pressurized fluidized bed combustor (PFBC) systems. The most promising of these so far, is the ceramic candle filter unit utilizing silicon carbide filters. A unit of this type was currently being demonstrated at the Tidd PFBC site under the Clean Coal Technology (CCT) Program. Several other demonstrations of this unit are planned under additional CCT projects including the Tampa Electric IGCC demonstration and Sierra Pacific's Piñon Pine IGCC project. This unit will allow removal of particulates to levels acceptable to a gas turbine expansion section. This unit has recently become available as a commercial offering with the attendant performance guarantees.

Char Combustion

In this system, the fluidized bed char combustor provides the energy for gasifier air/steam heating, and boiler heat for the steam cycle. Char burned in the combustor has a carbon content of approximately 87%. The combustor operates at a temperature of 843°C (1550°F) with 20% excess air. Tubes are included in the combustor system to provide air/steam heating and to recover heat for the steam cycle. Carbon conversion in the combustor was assumed to be essentially complete. As discussed earlier, the commercial version of this gasifier is likely to have very high carbon conversion (> 99%). In this case, a char combustor would be unnecessary and energy for air/steam heating and wood drying would be obtained from elsewhere in the process.

Low Pressure Indirectly Heated Gasification - The BCL Gasifier

The low pressure indirectly-heated gasifier selected for this study was developed at Battelle Columbus Laboratory specifically for biomass gasification. A schematic of this gasifier integrated with the combined cycle is shown in Figure 3. The distinctive feature of the BCL unit was that unlike direct-fired gasifiers which use both steam and air, only steam was injected with the biomass to promote gasification. Therefore, the fuel gas has a higher heating value than that produced by direct-fired gasifiers. Without rehumidifying the fuel gas, the higher heating value of the fuel gas is 16.4 MJ/m3 (441 Btu/scf); if the fuel gas is rehumidified to 20% by weight, its higher heating value is 14.2 MJ/m3 (379 Btu/scf). The heat necessary for the endothermic gasification reactions was supplied by sand circulating between a fluidized bed char combustor and the gasification vessel. In addition to acting as the heat source, the sand was the bed material for the gasifier, designed as an entrained fluidized bed reactor. Of the total amount of sand circulating between the gasifier and char combustor, 0.5% is purged to prevent ash build-up in the system. Because this stream is nearly 100% sand, it is likely that its means of disposal would not be subject to the same requirements as pure ash from directly-heated gasifier systems.

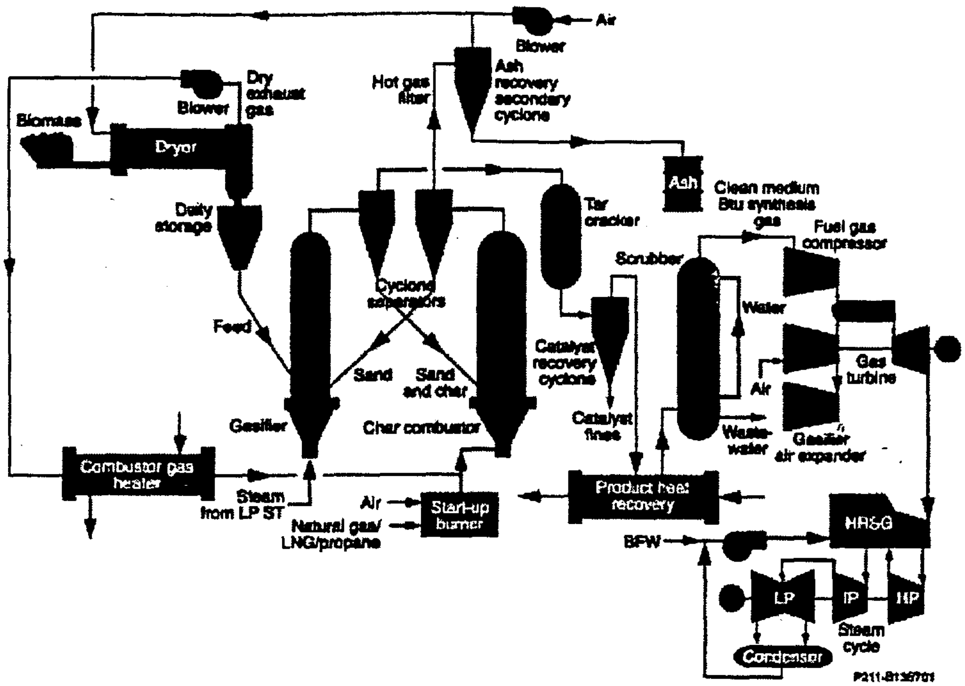

Figure 3. Low Pressure Indirect BIGCC Schematic

This integrated gasification combined cycle plant was simulated in ASPEN/SP; a Fortran subroutine controls the simulation of the gasifier. The equations in this subroutine which control the component mass balance in the gasifier were developed from regressing the experimental data from the Battelle Columbus Laboratory 9 T/day PDU [7] [8]. Because of the low pressure, wood from the dryers was fed to the gasifier using an injection screw feeder. According to the simulation, the gasifier operates at nearly atmospheric pressure (172 kPa, 25 psi) and 825°C (1517°F). The design parameters and operating conditions of the indirectly heated gasifier are shown in Table 5. The product gas composition, calculated in the Fortran subroutine during the ASPEN simulation is shown in Table 6. The composition of the char is dependent upon the temperature of the gasifier, which in turn is dependent upon the heat balance between the char combustor and the gasifier. The char composition is determined, therefore, by the Fortran subroutine, and is shown in Table 7.

Table 5: Indirectly Heated Gasifier Design Parameters and Operating Conditions

Gasifier temperature	826°C (1519°F)
Gasifier pressure	0.17 MPa (25 psi)
Dried wood feed to gasifier	1,486 T/day (1,638 t/day)
Dried wood moisture content	11%
Gasifier internal diameter	2.93 m (9.6 ft)
Steam / wood ratio (wt/wt, MAF)	0.45
Sand / wood ratio into gasifier (wt/wt)	34.4

Table 6: Indirectly Heated Gasifier Product Gas Composition, dry basis

Component	Volume %
H2	21.22
CO	43.17
CO2	13.46
CH4	15.83
C2H2	0.36
C2H4	4.62
C2H6	0.47
Tars	0.40
H2S	0.08
NH3	0.37
LHV = 13.2 MJ/m3 (354 Btu/SCF) HHV = 14.2 MJ/m3 (379 Btu/SCF)	

Table7: Char Composition in the Indirectly-Heated Gasifier Simulation

Component	Weight %
Ash	3.23
Carbon	66.46
Hydrogen	3.09
Nitrogen	0.04
Sulfur	0.03
Oxygen	27.15

Drying Requirements

To assess the feasibility of operating the low pressure indirectly-heated gasifier without a drying system, different feedstock moisture levels were tested. Results, showing the relationship between moisture content of the feed versus gasifier temperature, are shown in Figure 4. These curves represent two system designs where the air to the char combustor is fed at either ambient conditions (15°C) or is preheated to 538°C. It was found that as the moisture level increases, the heat available from the char is no longer sufficient to maintain gasification and also vaporize the water in the feed. Figure 4 shows that if the char combustion air is not preheated, a dryer is necessary. In real operation, the gasifier temperature would continue to plummet below 650°C; the curve plateaus at this point because of the lower limit set on the gasifier temperature in the ASPEN simulation. Although a dryer is still deemed necessary if the moisture content of the feed is higher than approximately 25% and the air is preheated, the drying requirements can be reduced from what is typically thought to be required (approximately 10% moisture levels) and still maintain temperatures necessary for gasification.

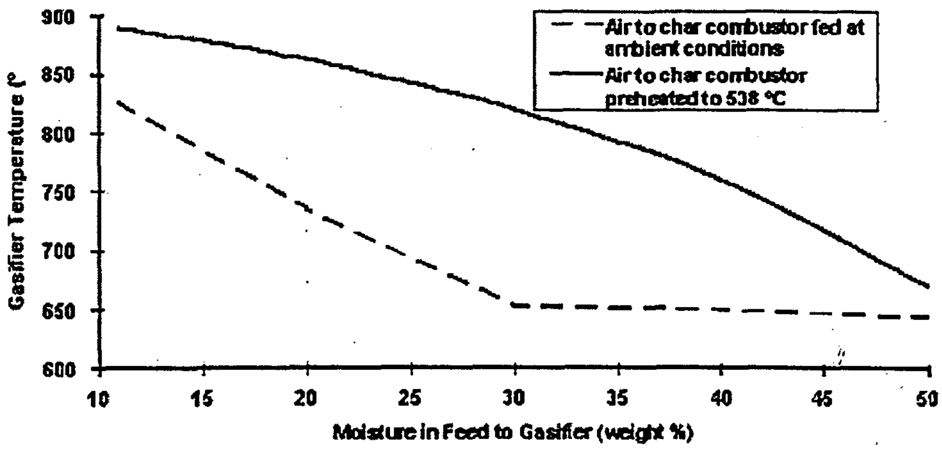

Figure 4. Gasifier Temperature as a Function of Feedstock Moisture Content

Gas Clean-up

Fuel gas produced by the low pressure indirectly heated gasifier was cleaned using a tar cracker to reduce the molecular weight of the larger hydrocarbons, and a cyclone separator to remove particulates. A direct water quench was used to remove alkali species and cool the gas to 97°C for compression. As an additional safeguard, a baghouse filter was also included to remove any fine particulates that were not removed in the cyclone separator, and to ensure that any alkali species that were not removed in the quench are not fed to the compression and turbine systems. Although a tar cracker was not necessarily required since the gas was cooled using a direct water quench, one was included in this design to avoid losing the substantial heating value of the tars.

Fuel Gas Compression

Compression of the fuel gas prior to the gas turbine combustor was accomplished in a five stage centrifugal compressor with interstage cooling. This series of compressors increased the pressure from 172 kPa to 2,068 kPa (25 psi to 300 psi). The maximum interstage temperature was 158°C, and the interstage coolers reduced the temperature of the syngas to 93°C. This unit operation was optimized at five stages according to the purchased equipment cost and horsepower requirements. After compression, the syngas is heated indirectly to 371°C with process heat from the quench and char combustor flue gas.

Rehumidification of the Syngas Prior to Combustion

For the indirectly-heated gasifier, the efficiency, electricity output, and cost of electricity were also studied as a function of the moisture level of the syngas prior to combustion in the gas turbine combustor. During quench and compression, the water in the syngas is reduced to 7% by weight. Feeding this syngas directly to the combined cycle results in an efficiency of 35.67% and a cost of electricity of $0.0576/kWh on a constant dollar basis. If, however, a portion of the water that drops out of the syngas during compression is compressed and re-added such that the moisture content is 20% by weight, the efficiency and constant dollar cost of electricity are 35.40% and $0.0572/kWh, respectively. Thus, rehumidifying the syngas prior to combustion decreases the overall efficiency of the system but increases the power output; this results in a slightly lower cost of electricity, although 2% more biomass feed is required. Increasing the moisture level of the fuel gas past 20% is not feasible as the gas turbine mass flow limit is reached and the ability of the turbine combustor to burn the wood is decreased. Naturally, the heating value of the fuel gas is reduced when water is added to it. Without rehumidifying the fuel gas, the higher heating value of the fuel gas is 16.4 MJ/m3 (441 Btu/scf); at 20% by weight, its higher heating value is 14.2 MJ/m3 (379 Btu/scf).

Low Pressure, Air-Blown Gasification

The last commercially available gasifier type investigated was the low pressure direct system. The most well-known gasifier of this type is that offered by TPS and is also known as the Studsvik gasifier. The TPS gasifier has been selected for the World Bank's Global Environment Facility (GEF) project in Brazil. The GEF project will couple a TPS gasifier fueled with eucalyptus to a GE LM-2500 aero-derivative gas turbine system for power generation in northern Brazil. The TPS gasifier was also examined in a biomass IGCC application as part of a DOE/NREL sponsored site-specific feasibility study conducted by Weyerhauser [9]. Other low pressure, direct air-blown gasifiers that have been operated with biomass include the Lurgi circulating fluidized-bed gasifier and the Energy Products of Idaho (EPI) gasifier. A schematic of the system used in this study is shown in Figure 5.

Table 8: Low Pressure, Direct-Fired Gasifier Design Parameters and Operating Conditions

Gasifier temperature	870°C (1,600°F)
Gasifier pressure	0.14 MPa (1.36 atm)
Fuel gas pressure	1.89 MPa (18.6 atm)
Dried wood feed to gasifier	1,460 T/day (1,606 t/day)
Dried wood moisture content	15.8%
Air / wood ratio (wt/wt, MAF)	2.1
Steam / wood ratio (wt/wt, MAF)	0

Unfortunately, little concrete data is publicly available on the operating conditions, reactant ratios, and fuel gas produced by the TPS gasifier. For this study, therefore, data from biomass testing in a small-scale Lurgi circulating fluidized-bed gasifier [10] was used to estimate gasifier performance. The operating conditions selected for this gasifier were a temperature of 870°C (1,600°F) and a pressure of 0.14 MPa (1.36 atm). Survey of available data on gasifiers of this type indicates that steam is rarely used as part of the gasification process. It was noted that the moisture content of the dried biomass used in these gasifiers is somewhat high (up to slightly over 20%); it is assumed that this moisture serves as the source of "steam" for the steam-carbon gasification reaction. Relatively high air/biomass ratios also seem to be common for gasifiers of this type, though again, detailed information on this point is difficult to obtain. Table 8 summarizes the operating conditions for the gasifier used in this case.

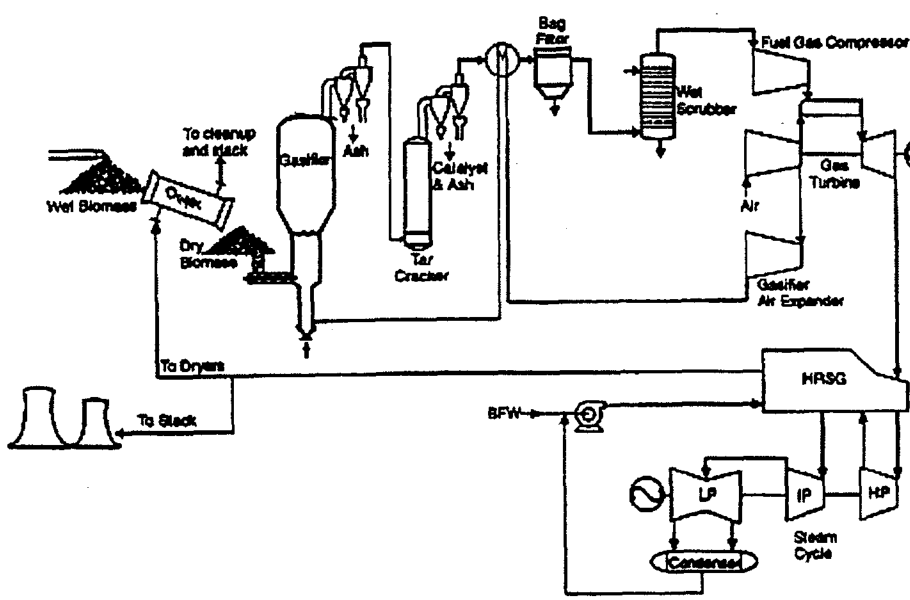

Figure 5. Low Pressure Direct BIGCC Schematic

In order to estimate gasifier performance and fuel gas composition, a quasi-equilibrium model was used. This process employed the RGIBBS model in ASPEN/SP along with its capability to accommodate equilibrium approach temperatures for specified reactions. The problem was further complicated by the lack of information on air preheat temperature. The problem was solved by selecting the gasifier temperature and pressure and a probable air/biomass ratio. The air preheat level was adjusted to yield a heat loss expected for a unit of this scale (1.5%), and the equilibrium approach temperatures for the various gasification reactions adjusted to match reported fuel gas composition. These, of course, are not independent variables so an iterative approach was required. Nitrogen in the fuel gas provided a check on the selected air/biomass ratio. The derived fuel gas composition after the gas cleaning and conditioning described below is shown in Table 9.

Gasifier Design

Owing to the aforementioned dearth of detailed information on this gasifier, it was not possible to perform a detailed gasifier design. Instead, the design and cost information for the TPS gasifier case contained in the Weyerhauser feasibility study was scaled to fit the system examined in this report. Portions of the following system description in this section are extracted from the Weyerhauser final report, and additional details can be found therein.

Table 9: Low Pressure, Direct-Fired Gasifier Product Gas Composition

Component	Volume %
H_2	18.87
CO	23.66
CO_2	8.29
H_2O	4.85
N_2	44.22
CH_4	0.11
LHV = 4.8 MJ/m3 (129 Btu/SCF)	

Biomass is fed to the gasifier by two screw feeders that are isolated from the upstream components by pressurized rotary valves. The gasifier is a two-zone fluidized bed rector that used sand as a bed material. Biomass fed to the gasifier drops into the lower, dense phase fluidized bed. This portion of the gasifier provides sufficient residence time for gasification of the larger biomass particles. Preheated primary air enters the gasifier near the base of the vessel and maintains fluidization of this dense portion of the bed. Secondary air in added above the dense bed to produce a "fast" fluidized bed region. In this section, remaining fuel is fully pyrolized and gasified by the combined action of heat, air, and gas components.

Air for gasification is extracted from the gas turbine compressor and let down to gasifier operating pressure through a turbine. This generates an additional 8.4 MW_e of power, almost half the amount required to drive the fuel gas compressor. The air extraction rate in this case was such that the combined air and combustion product mass flow through the gas turbine expansion section and, thus the power output, was not significantly different from the design values on natural gas.

Gas Clean-up

Fuel gas exiting the gasifier cyclones enters a circulating fluidized bed tar cracking unit. This unit reduces the quantity of higher hydrocarbon species in the fuel gas that could otherwise foul the fuel gas cooler, plug the fabric filters, and increase wastewater treatment loads from the gas scrubber. Dolomite is used as the bed material in the tar cracker. The higher temperature of the tar cracker (920°C, 1688°F) also ensures conversion of any un-gasified solids that escape the gasifier.

After exiting the second stage tar cracker cyclone, the fuel gas enters the syngas cooler. In a slight modification to the Weyerhauser report design, this unit is used to preheat gasification air as well as provide heat to the steam cycle. In actual practice, the potential safety risk of this scheme would have to be carefully evaluated though we have some assurances that such an approach is feasible[11]. In the syngas cooler, the temperature of the fuel gas is reduced to 288°C (550°F).

Any particulates remaining in the fuel gas are removed in a bag filter unit. As the fuel gas is cooled, volatile alkali species present in the gas stream condense on the remaining particulate matter and are removed from the system by the filter bags. The particulate-free fuel gas is cooled further in a direct contact water scrubber that removes any trace higher hydrocarbons and most of the water in the fuel gas stream. This operation also removes a significant amount of the ammonia from the fuel gas. Following this step, the gas is further washed with a dilute sulfuric acid stream. These combined steps remove over 95% of the ammonia from the fuel gas. This ammonia would otherwise be likely to produce NO_x in the gas turbine combustor. Purge streams from both towers are sent to wastewater treatment. The fuel gas then enters a knockout drum prior to the fuel gas compressors.

Fuel Gas Compression

Following final fuel gas cleaning, the fuel gas is compressed for introduction into the gas turbine combustor. Although the turbine pressure ratio is only 14.9, the fuel gas is compressed to 1.89 MPa (18.6 atm) to allow for pressure drop across the fuel control valve. This compression is accomplished in a multi-stage, inter-cooled centrifugal compressor. This portion of the process was not detailed in the Weyerhauser report and so was evaluated as part of the ASPEN/SPsimulation. It was noted that fewer compression/inter-cooling stages were required to maintain gas temperature within acceptable limits in this case than in the indirect gasifier case. Presumably this is due to differences in the gas composition.

Combined Cycle Power Generation

Since the output, performance, and conditions of the combined cycles vary across the cases examined, only the general features of the power island are discussed here. Output and efficiency data are contained later in the discussion of the results of this study. All of the equipment discussed in this section was commercially available. The MS-6101FA gas turbine will see its first commercial demonstration at Sierra Pacific's Piñon Pine IGCC plant being funded under DOE's Clean Coal Technology Program.

Gas Turbine

Hot (538°C for the pressurized gasifier system, 371°C for the low pressure indirectly-heated gasifier system, 225°C for the low pressure direct gasifier) clean fuel gas is introduced into the gas turbine combustor along with air from the high pressure turbine compressor. All scenarios tested, including those with direct quench produced fuel gas that was well within the projected requirements for combustion of low energy content gas in gas turbines. The use of a direct quench or humidification in some of the systems studied produces a fuel gas with higher moisture levels which helps reduce formation of nitrogen oxides in the combustor and increases the mass flow through the turbine expander and, thus, the turbine's power output. However, in all if the cases studied, the overall increase in mass flow through the turbine expander was less than 10% since the increased flow of low energy content fuel gas was partially offset by gasification air extracted from the compressor discharge.

An important technical qualification to selection of the turbines in this study is the ability to extract gasification air for the air-blown gasifiers from the compressor discharge. This extraction was necessary not only to realize the efficiency benefits of tight integration, but to maintain compressor/turbine power balance. Because of the reduced heating value of the gasifier product gas, a larger amount of this fuel gas (compared to natural gas) was required to achieve design turbine firing temperatures. This additional fuel can increase the mass flow into the turbine section, depending on the amount of air extracted, and thus the turbine's power output. Without air extraction, this increase can cause compressor stall. In the case of the indirectly heated gasifier, air extraction is probably not necessary because the fuel gas produced is of a medium heat content. The air/biomass ratio for the low pressure direct gasifier (and thus the air extraction rate) is such that the turbine mass flow and power output is essentially unchanged from the natural gas design values.

The aero-derivative gas turbine selected for this study was the General Electric LM5000PC. The LM5000 has a higher pressure ratio (24.8) and firing temperature (in excess of 1150°C) than the utility machines selected for previous biomass IGCC studies. The smaller size turbines used in earlier studies were selected because of the smaller amounts of biomass fuel available compared to systems using coal or natural gas. Unfortunately, small scale utility turbines are generally the last to benefit from technological advances in the field. Therefore, resulting system efficiencies were correspondingly low relative to coal or gas IGCC systems. One of the goals of this study was to evaluate the effect the latest turbines had on biomass system efficiency. A combined cycle was selected rather than the steam-injected LM5000 because of the lower water usage required for the combined cycle. This allows maximum flexibility for siting the plant, reduces feed water treating, and conserves water resources. The similarly sized and higher efficiency LM-6000 turbine was not selected for the study because of its even higher pressure ratio of 30.

Air extraction has not yet been demonstrated with the LM5000 gas turbine; however, an investigation of the feasibility and mechanics of this practice has been investigated by DOE's Fossil Energy program and such a scheme has been investigated with the related LM2500 turbine being used in the GEF project. General Electric and other turbine manufacturers are incorporating air extraction provisions into some utility turbine designs including the MS-6101FA discussed below. Westinghouse also commercially offers for biomass-derived as well as natural gas fuels, the 251B12 "ECONOPAC™" combined cycle system. This package is nominally rated at 50 MW, includes low-NO_x combustion technology, and has a net efficiency of 46.5% (LHV basis) on natural gas fuel.

Within the last few years, a smaller, advanced utility gas turbine has also become available, the GE MS-6101FA. This turbine moves GE's "F" technology (high firing temperature, high efficiency) down from the company's 160 MW MS-7221FA machine to a 70 MW class machine. This increases the Frame 6 efficiency to 34.2% (simple cycle, LHV, natural gas) from the 30% range previously typical for this scale and type of machine. The increased mass flow and temperature of the turbine exhaust also allows the use of more sophisticated steam cycles in this size range. The pressure ratio of utility machines (14.9 for the 6FA) was also more compatible with demonstrated biomass gasifier operation. Further, the MS-6101FA is able to accommodate extraction of up to 20% of the compressor discharge flow to supply a gasifier[12]. A recent Gas Turbine World article [13] also discusses GE's 20% uprate of this turbine's power output when fueled with synthesis gas. For these reasons, systems incorporating the Frame 6FA turbine were also evaluated. It was believed that the substantially increased efficiency would offset the system size increase and keep the feed requirements within what might be available from a dedicated feedstock supply system (DFSS).

Heat Recovery Steam Generator

Gas turbine exhaust was ducted to the heat recovery steam generator (HRSG). For the LM5000 based cases, the HRSG design and conditions were derived from published information on the LM5000 steam-injected turbine [14]. This was done to avoid issues of availability of high performance HRSG's for small-scale turbines and the associated cost data. The HRSG incorporates a superheater, high and low pressure boilers and economizers. Superheated steam (394°C, 5.3 MPa) was provided for the gasifier and the steam cycle. Medium pressure steam (1.4 MPa) was also provided for the steam cycle. The exhaust temperature from the HRSG in all cases, 140°C (284°F), was sufficiently high to avoid any possible corrosion in the stack and to mitigate plume visibility issues.

Given the higher turbine exhaust temperature (618°C, 1145°F), a more complicated HRSG was utilized for the systems integrated with the MS-6101FA gas turbine. In this case, the HRSG provides steam superheating and steam reheat, as well as the high and low pressure boilers and economizers. For all designs, HRSG's were designed with superheater temperature approaches of 16-33°C (30-60°F) and pinch points of 22°C (40°F). Boiler blowdown was assumed to be 2%, and feedwater heating and deaeration are performed in the HRSG system. All feedwater pumps are motor driven rather than steam turbine driven. In all direct gasifier systems studied, supplemental heat for drying is provided by flue gas extraction from an appropriate point in the HRSG.

Steam Turbine System

The steam turbine system for the LM5000 cases was relative simple comprising high (HP) and low pressure (LP) power turbines and a generator. Superheated steam (394°C, 5.3 MPa) was introduced into the high pressure turbine and expanded to 1.4 MPa (200 psia). Exhaust from the HP turbine was combined with additional steam from the LP boiler and introduced to the LP turbine which exhausts to the condenser at 6,900 Pa (2 in. Hg).

For the MS-6101FA case, the steam cycle was somewhat more advanced. Superheated steam at 538°C and 10 MPa (1000°F, 1465 psia) was expanded in the HP turbine. Gasification steam, where required, was extracted from the HP exhaust. The remaining steam was combined with steam from the LP boiler, reheated, and introduced into the intermediate pressure (IP) turbine. Exhaust from the IP turbine was passed though the LP turbine and condensed at 6,900 Pa (2 in. Hg). Expanded steam quality leaving the LP turbine in all cases was 90 per cent. Assumed generator efficiency was 98.5%.

General Facilities

A mechanical induced-draft cooling tower was assumed for each design. This includes all of the necessary pumps for condenser cooling and makeup water needs. Balance of plant equipment includes plant water supply and demineralization facilities, firewater system, waste water treating, service and instrument air system, and the electric auxiliary systems. General facilities included are roads, administrative, laboratory and maintenance buildings, potable water and sanitary facilities, lighting, heating and air conditioning, flare, fire water system, startup fuel system, and all necessary computer control systems. In addition, the greenfield case included costs for land and land development, as well as an electrical substation for transmission access.

Overall System Performance

Process conditions and system performance for each of the cases examined are summarized in Table 10. Net system output ranges from 55.5 MW_e for the LM5000 cases to 131.7 MW_e for the high pressure gasifier MS6101FA case. Net system efficiency ranges from 35.4% for the low pressure indirect gasifier case to 39.7 for the high pressure gasifier MS-6101FA case. Gas turbine output and efficiency based on fuel heating value are greater than those listed in the literature for natural gas fuel. These increases are primarily the result of high fuel gas temperatures and the increased mass flow through the turbine expander (due to lower energy content fuel gas). The gas turbine power output in the high pressure gasifier case is in excess of the 20% performance augmentation claimed by GE for their turbine operated on synthesis gas fuel. The turbine may need to be de-rated in this case using more sophisticated modeling techniques.

The performance results from the simulation demonstrate a number of salient points. It was clear that use of advanced turbine technology results in significant efficiency gains. Predicted efficiency of the worst case considered was nearly eight percentage points higher than the best previous biomass IGCC system study. It is also clear that the lower gas turbine efficiency of the MS-6101F (as compared to the LM5000) was more than compensated by the more advanced steam cycle that was possible with its increased exhaust flowrate and temperature.

Table 10: Process Data Summary and System Performance Results

	High pressure gasifier, aero-derivative gas turbine	High pressure gasifier, advanced utility turbine	Low-pressure indirectly-heated gasifier, advanced utility gas turbine	Low pressure air-blown gasifier, advanced utility gas turbine
Gasifier Requirements				
Wood flowrate, kg/s (lb/hr)	8.9 (70,261)	19.1 (151,361)	17.2 (136,494)	16.9 (133,838)
Air flowrate, kg/s (lb/hr)	9.2 (72,674)	18.1 (143,178)	0	29.7 (235,469)
Steam flowrate, kg/s (lb/hr)	2.5 (20,044)	5.4 (43,181)	7.7 (61,346)	0
Fuel Gas				
Fuel gas flowrate, kg/s (lb/hr)	23.0 (182,520)	47.7 (378,360)	14.5 (114,734)	43.8 (347,040)
Fuel gas				

heating value, LHV, wet basis, MJ/m^3 (Btu/SCF)	4.3 (115)	4.3 (115)	13.2 (353.9)	4.8 (129)
Power Island				
Gas turbine	GE LM5000PC	GE MS-6101FA	GE MS-6101FA	GE MS-6101FA
Turbine PR	24.8	14.9	14.9	14.9
Turbine firing temperature, °C (°F)	1,154 (2,110) estimated	1,288 (2,350) estimated	1,288 (2,350)	1,288 (2,350)
Steam cycle conditions, Mpa/°C /°C| (psia/°F/°F)	5.3/395 (770/742)	10/538/538 (1,465/1,000/1,000)	10/538/538 (1,465/1,000/1,000)	10/538/538 (1,465/1,000/1,000)
Power Production Summary				
Gas turbine output, MW_e	50.3	93.1	82.1	72.9
Steam turbine output, MW_e	8.95	46.6	55.1	47.6
Internal consumption, MW_e	3.79	8.02	15.2	15.1
Net system output, MW_e	55.5	131.7	122	105.4
Net plant efficiency, %, HHV basis	36.7	39.7	35.40	37.9

Economic Analysis

The selling price of electricity in 1990 (the base year for this report) was $0.047/kWh, $0.073/kWh, and $0.078/kWh for industrial, commercial, and residential customers, respectively (EIA, Annual Energy Review, 1993). By calculating the economics of the processes being studied and comparing the results to the prices within the electricity generating market, the potential profitability can be assessed.

Economic Analysis Methodology

The levelized cost of electricity from three BIGCC systems was calculated by setting the net present value of the investment to zero. The method and assumptions that were used are based on those described in the EPRI Technical Assessment Guide (TAG) [15] and reflect typical utility financing parameters. Independent power producers or cogenerators would clearly have different analysis criteria. The spreadsheet used for COE calculations was developed at DOE's Morgantown Energy Technology Center. A summary of the economic assumptions is presented in Table 11.

Table 11: Economic Assumptions					
December, 1990 dollars					
30 year project life					
30 year book life					
20 year tax life					
Accelerated Cost Recovery System (ACRS) depreciation					
Federal and state income tax rate = 41%					
Yearly inflation rate for calculation of current dollar cost = 4%					
Financial Structure		Current Dollar		Constant Dollar	
Type of Security	% of Total	Cost, %	Return, %	Cost, %	Return, %
Debt	50	8.6	4.3	4.5	2.3
Preferred Stock	8	8.3	0.7	4.2	0.3
Common Stock	42	14.6	6.1	10.3	4.3
Discount Rate (cost of capital)			11.1		6.9

Capital Cost Estimates

Capital costs for the systems were estimated using a combination of capacity factored and equipment-based estimates. Capacity factored estimates utilize the ratio of the capacity (flowrate, heat duty, etc.) of an existing piece of equipment to the new equipment multiplied by the cost of the existing equipment to estimate the cost of the new equipment. A scale-up factor particular to the equipment type was applied to the capacity ratio. The equipment-based estimates were determined from more detailed equipment design calculations based on the process conditions and results of the simulations. All costs were estimated in instantaneous 1990 dollars. Where necessary, costs were corrected to 1990 using the M&S or Chemical Engineering equipment cost indices. A charge of 20% of the installed cost of the major plant sections was taken to account for all balance of plant (BOP) equipment and facilities. Additional costs a for substation and land were included for the greenfield case. The major equipment costs were multiplied by a factor to arrive at the total direct cost of the installed equipment. Table 12 lists the factors used to determine total direct cost. In the design of the various pieces of process equipment, every effort was made to specify units that were modular and capable of being shop fabricated and shipped by rail. It was believed that this approach will help keep capital costs low and shorten the learning curve in deployment of plants of this type.

Table 12: Cost Factors Used for Calculation of Total Direct Cost	
Installation	15% of delivered equipment cost
Piping	45% of delivered equipment cost
Instrumentation	10% of delivered equipment cost
Buildings and Structures	10% of delivered equipment cost
Auxiliaries	25% of delivered equipment cost
Outside Lines	10% of delivered equipment cost
Total Direct Plant Cost (TDC)	**215% of delivered equipment cost**

Wood Preparation and Drying Costs

The majority of the equipment necessary for solids handling, storage, sizing, and conveying was scaled from a study performed by Tecogen for a similar sized IGCC plant based on the BCL indirectly heated gasifier [16]. A magnetic separator was added as one was not explicitly included in the Tecogen analysis. Costs for the separator were determined from a detailed study on wood handling equipment [17]. The dryers were sized based on the methodology outline in the Tecogen study and the costs were developed from Perry's Chemical Engineers' Handbook [18]. A baghouse was added to remove wood particles from the dryer exit. Costs for the baghouse were developed used the CHEMCOST program. The equipment included in the wood preparation and drying section includes the following: truck unloaders and truck scales, chip yard handling equipment, one week storage paved chip yard, one day storage silo, sizing bin/chip hogger, conveyor/bucket elevator, magnetic separator, rotary drum dryers, and baghouse filter.

Gasification Costs

The costs of the high pressure air-blown gasifier and its associated equipment were initially based on work done for EPRI by Southern Company Services [19]. Because of the similarities in design and operating conditions, the cost for the gasifier and its associated equipment was based on that for the Kellogg-Rust-Westinghouse (KRW) coal gasifier. While the report was being revised and finalized, however, more recent and applicable cost data became available. In May of 1995, Northern States Power (NSP) completed a report on a site-specific feasibility study that evaluated biomass gasification combined cycle technology for rural power generation [20]. This report included cost estimates for the Tampella Power Systems (not associated in any way with TPS) biomass gasifier. Tampella are a licensee of the IGT gasifier technology and it is believed that their design and costs are representative of the high-pressure gasifier used in this study. Therefore, the gasification section cost contained in the NSP report was scaled and modified to reflect a projected n^{th} plant cost and used in the final version of the cost figures for systems incorporating the high pressure direct gasifier. These revised, higher, costs also reflect the consensus position on the cost of n^{th} plant biomass IGCC systems developed in discussions with EPRI, Princeton, Colorado School of Mines, and others and documented in an EPRI paper [21]. The original cost figures can be found in an ASME paper by the authors [22]. For the utility turbine case, two gasification trains of equal size were used to provide the required quantity of fuel gas to the turbine. The boost compressor for the gasification air was sized based on the ASPEN/SP simulation and its cost determined from a standard references [23],[24],[25],[26].

The costs associated with the low pressure indirectly heated gasifier were determined by studying and evaluating the accuracy of costs developed by several independent sources [27],[28],[29],[30]. It was assumed that two gasification trains of equal capacity will be needed. Equipment included in the gasification section include the gasifier, char combustor, char combustor cyclone, sand surge pots, ash cyclone, sand makeup hopper, startup burner and blower, and steam supply valves.

The costs of the low pressure air-blown gasifier were developed from information contained in the Weyerhauser feasibility study [31] for the TPS gasification system. The capital costs are reported by overall plant section (e.g. "Gasification", "Power Block") so detailed analysis and scaling was not possible for each piece of equipment. Given that the gasification system design was essentially identical to that used in our simulation, the entire gasification section cost was scaled to the size required for use with an MS-6101FA gas turbine using an overall scale factor of 0.8. This assumes, of course, that a single train could be increased in scale by 60%. Otherwise, two parallel trains would be required. This would increase the gasification section capital cost by approximately 15%.

Gas Clean-up Costs

Tar cracker

The initial tar cracker design was developed using laboratory data [32] including space velocities of 2000 hr^{-1}; however, this resulted in extremely large and shallow beds. Further examination of the laboratory data revealed that very large space velocities were utilized to quickly test catalyst life. Therefore, a reduced space velocity (35% of the lab value) was adopted for the design. This resulted in reasonable superficial gas velocities and a vessel size of 4.26 x 12.8 meters (14 x 42 ft.). The module cost for the tar cracker was determined using the CHEMCOST program and the cost factor applied.

High temperature gas cooling
For the cases that used a direct quench, the cost of a quench pump was determined with the CHEMCOST program. For the indirect gas cooling case, the area and size of the heat exchanger required was calculated utilizing standard methods [33] and based on data from the system simulation. The cost of this indirect cooler was determined from the CHEMCOST program. In both cases, a cost factor of 0.7 was applied to the basic equipment cost.

High temperature particulate removal
Based on information supplied by the equipment vendor [34], it was believed that a hot gas filtration unit similar in size to that being demonstrated with the Tidd pressurized fluidized bed combustor (PFBC) system under the Clean Coal Program would be appropriate for a gasification train of the size being evaluated in this report. The vendor supplied an FOB cost for the hot gas filtration unit. The installation factor applied to the particulate filter was reduced slightly given the highly modular, shop fabricated nature of the unit. This cost was further confirmed against data contained in the NSP report which used a similar system.

Compression Costs for Low Pressure Gasifier Systems

In the low pressure indirectly heated gasifier plant, a five stage compression system with interstage cooling was used to boost the pressure of the syngas prior to combustion in the gas turbine combustor. The purchase price and total power requirement for this compression operation were estimated to be \$3.8 MM and 9.6 MW_e, respectively. This unit was optimized at five stages according to the purchased cost and horsepower requirements which were higher for both four stage (\$4.1 MM, 9.7 MW_e) and six stage (\$3.9 MM, 9.7 MW_e) compression systems.

The cost for the fuel gas compressor is included in the gasification section system cost from the Weyerhauser report that was used to develop an overall cost for the gasification system up to the combined cycle system. Therefore, cost details for the compressor itself are not available. Data from the ASPEN simulation indicates that two or three compressor stages with inter-cooling would be required to raise the fuel gas to the necessary pressure. The number of stages is largely constrained by the allowable outlet temperature of each stage and the thermodynamic characteristics of the fuel gas.

Char Combustor Cost for High Pressure Gasifier System

The base cost for the char combustor for the direct gasification systems was determined from the ENFOR reports [35] on commercially available equipment for wood combustion and the result independently confirmed [36]. The size was determined based on the heat duty of the unit. The total cost for the combustor system was reduced by 30% from that found in the ENFOR reports, since a substantial fraction of the heat recovery in the commercial system (and therefore a substantial fraction of the heat exchange area) was not needed for this application. The system cost included the feed system, primary air, boil, and ash removal system. The final cost for the wood handling and drying section was compared with an independent cost estimate for a system of similar size[37], and found to be similar.

As discussed earlier, if gasifier carbon conversion achieves high levels in the final commercial, this plant section will not be required. This would result in a total capital requirement savings of \$2.1 million in the aero-derivative turbine case and \$3.3 million in the utility gas turbine case as well as an indeterminate amount of O&M expense.

Combined Cycle Power Generation Costs

Gas Turbine
Costs for the gas turbines utilized in this study were determined from published data [38] or from the manufacturer. Again, installation factors were slightly reduced because of the modular nature of the gas turbines and associated equipment.

Heat Recovery Steam Generator
The cost of the HRSG for the LM5000 turbine was estimated from published sources [39], [40]. The HRSG cost for the MS-6101FA turbine was scaled from the cost for a similar unit for the MS-7001FA turbine [41].

Steam Turbine System
The cost for the steam cycles for both systems were determined from capacity costs ($/kW) from a number of sources [42], [43], [44]. The estimated cost included all ancillary equipment for the cycle including mechanical draft cooling tower, feedwater pumps, condenser, etc, and was estimated to be $250/kW of the steam turbine output for the large steam cycles and $350/kW for the smaller steam cycles.

Total Plant Cost, Total Plant Investment, and Total Capital Requirements

To obtain the total plant cost (TPC), capital costs were added to the installed equipment cost for general plant facilities (10% of process plant cost), engineering fees (15%), and project contingency (15% of process plant cost + general plant facilities cost). The percentages were selected from ranges provided in EPRI TAG [45]. No process contingencies were applied to the individual plant sections as this was assumed to be a mature plant.

The total plant investment (TPI) was determined by adding the interest cost plus inflation to the TPC. The period of construction was assumed to be 2 years and construction interest was assumed to be 4.5%. The total capital requirement (TCR) for the plant was the sum of the TPC, TPI, royalties, startup costs, initial catalyst and chemicals, working capital, spare parts, and land (where applicable). A summary of the capital costs for each case was contained in Table 13.

Operation and Maintenance Costs

Operating and maintenance costs for the plant were based on an 80% capacity factor. Wood costs were assumed to be $46/Mg ($42 per bone dry ton). It was assumed that 2 operators per shift were required for the LM5000 based systems, and 5 operators per shift for the MS6101FA based system. This number of operators is substantially reduced over the EPRI TAG numbers and those contained in our earlier evaluation. This revised estimate is a result of developing operating trends and the consensus position arrived at between NREL, EPRI, Princeton, and others. A summary of annual operating costs for each case is contained in Table 14. Ash disposal costs for the indirectly-heated gasifier case are significantly higher than in the other cases because a large amount of sand was purged to prevent build-up of ash in the system. It is likely that this sand stream will not be disposed of in the same manner as pure ash streams from the other gasifiers, but a more conservative approach was taken in assuming the cost per tonne was the same.

Table 13: Capital Costs

	Installed Equipment Cost, $K (1990)				
Plant Section Description	High P, aero-deriv gas turbine	High P, greenfield plant	High P, utility gas turbine	Low P, indirect, utility gas turbine	Low P, direct, utility gas turbine
Wood Handling	2,173	2,173	4,346	4,400	3,478
Wood Drying	2,724	2,724	5,448	5,448	4,360
Gasification	20,972	20,972	44,475	14,185	|
Gas Cleanup	2,700	2,700	5,400	5,400	|
Tar Cracker				454	V
Direct Quench	15	15	30	30	33,481

Gas Turbine	13,161	13,161	17,220	17,850	17,220
HRSG	2,208	2,208	8,000	7,686	8,000
Steam Cycle	3,133	3,133	11,675	12,668	11,900
Boost Compressor	590	590	1,180	5,691	included with gasification
Char Combustor System	1,215	1,215	2,282	included with gasification costs	included with gasification
Balance of Plant	9,778	9,778	20,011	14,762	15,688
Substation	0	3,958	0	0	0
Subtotal, Process Plant Cost	58,669	62,627	120,067	88,575	94,127
General Plant Facilities	5,867	6,263	12,007	8,657	9,413
Engineering Fees		9,394	18,010	13,286	14,119
Project Contingency	9,680	10,333	19,811	14,615	15,531
Total Plant Cost (TPC)	83,017	88,617	169,895	125,333	133,189
Adjustment for Interest and Inflation	200	213	408	301	320
Total Plant Investment (TPI)	83,216	88,831	170,303	129,635	133,510
Prepaid Royalties	293	313	600	443	471
Startup Costs	2,250	2,382	4,649	4,081	3,683
Spare Parts	415	443	849	627	666
Working Capital	1,978	1,982	4,251	4,425	4,480
Land	0	1,000	0	0	0
Total Capital Requirement (TCR)	88,112	94,951	180,653	135,211	141,810
TCR ($/kW>	1,588	1,696	1,371	1,108	1,350

Table 14: Annual Operating Costs, $K					
	High P gasifier, aero- deriv. gas turbine	High P gasifier, greenfield plant	High P gasifier, advanced utility gas turbine	Low P indirectly-heated gasifier, utility gas turbine	Low-pressure air-blown gasifier, utility gas turbine
Wood (dry), $42/T	9,198	9,198	19,794	20,087	16,250
Water, $0.60/T	49	49	105	211	53
Ash Disposal Cost, $8.00/T	9	9	19	822	16
Operating Labor (incl. Benefits)	356	356	891	2,139	891
Supervision and Clerical	306	320	675	1,243	587
Maintenance Costs	1,660	1,772	3,398	2,507	2,664
Insurance and Local Taxes	1,660	1,772	3,398	2,507	2,664
Royalties	92	92	198	201	162
Other Operating Costs	102	107	225	414	196
Net Operating Costs	13,433	13,675	28,702	32,638	23,442

Cost of Electricity

Based on the above cost information and the economic assumptions listed in Table 11 and Table 12, the levelized costs of electricity (COE) were calculated for each case. The method utilized was based on that described in EPRI TAG [46]. The resulting electricity costs are summarized along with other pertinent cost data in Table 15. These electricity and capital costs are compared with a number of other studies in Figure 6 & Figure 7.

Table 15: Cost and Economic Summary for NREL Cases					
	High pressure gasifier, aero- deriv. gas turbine	High pressure gasifier, greenfield plant	High pressure gasifier, advanced utility gas turbine	Low-pressure indirectly-heated gasifier, utility gas turbine	Low-pressure air-blown gasifier, utility gas turbine
Output (Mw_e)	56	56	132	122	105
Efficiency (%, HHV)	36.01	36.01	39.70	35.40	37.9
Capital Cost (TCR, $/kW)	1,588	1,696	1,371	1,108	1,350
Operating Cost include. fuel ($1,000/yr)	13,433	13,675	28,703	27.983	23,4742
COE (¢/kW, Current $)	7.91	8.2	6.99	6.55	7.03
COE (Constant $)	6.1	6.31	5.39	5.11	5.43

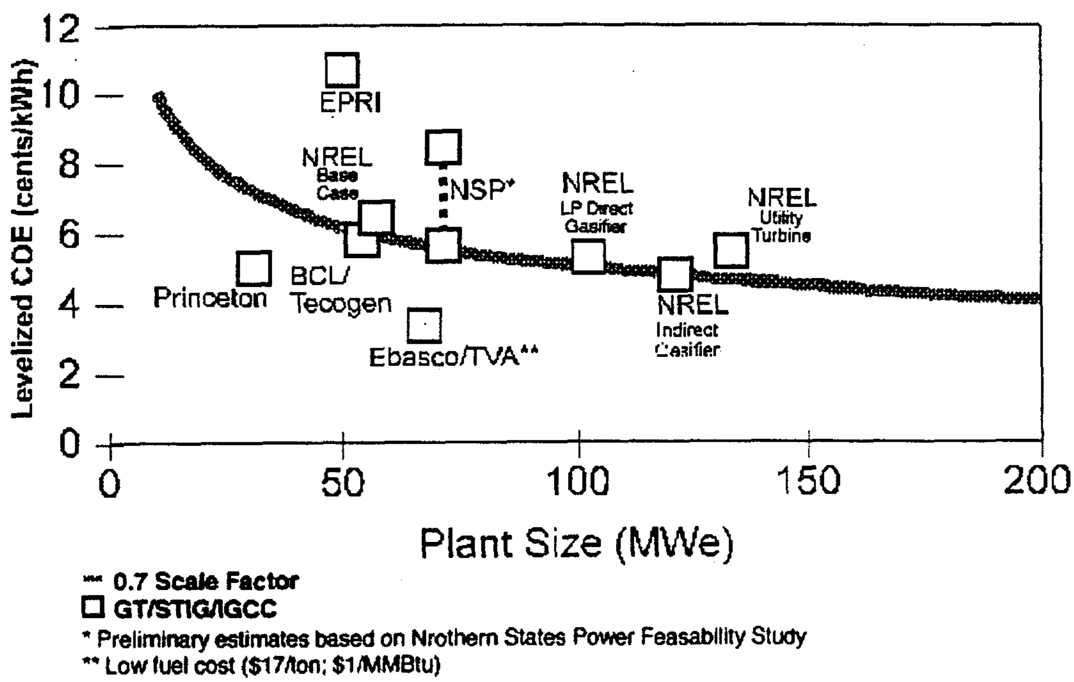

Figure 6. Cost of Electricity vs. Plant Size From Several Studies

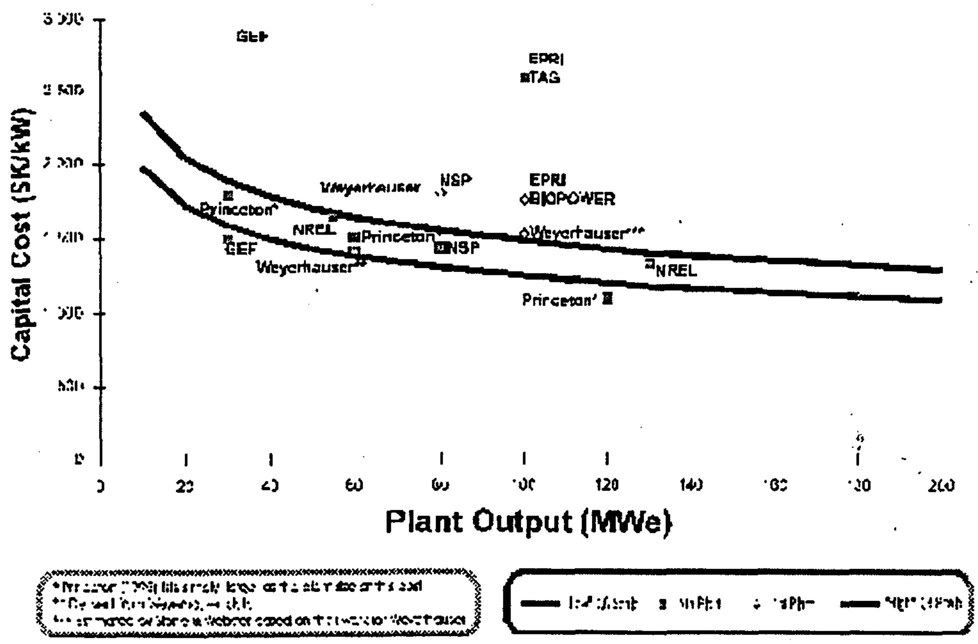

Figure 7. Capital Cost of Biomass IGCC Systems vs. Size From Several Studies

Analysis, Discussion, and Conclusions

It is clear from these analyses that gasification/turbine systems can produce electricity at up to twice the average efficiency of today's biomass power industry. The highest efficiency system examined here uses an advanced utility-scale gas turbine (the GE MS6101FA). Such a system benefits not only from economy of scale, but from the increased turbine efficiency and, perhaps most significantly, the reheat steam cycle that is feasible at this scale and turbine exhaust temperature.

Historically, generating systems of this scale (> 100 MW_e) have been deemed infeasible for biomass-based systems because of the associated feedstock requirements. However, the use of advanced combined-cycle technology reduces fuel requirements to manageable levels because of the striking increase in generating efficiency. Also, smaller, industrial-scale, gas turbines with very high efficiencies are being developed under the UDSOE's Advanced Turbine System (ATS) program. These are likely to be attractive for biomass systems as they will require reduced quantities of biomass to access high efficiency turbine systems.

Complementary to this trend is the development of dedicated feedstock supply systems that are intended to sustainably supply larger quantities of feedstock than were heretofore available. Properly managed, these trends are positioned to merge and provide a new generation of high-efficiency and cost-competitive biomass-based electricity generating stations.

It is also clear from this study however that even the most promising electricity cost from biomass is higher than currently quoted avoided costs and new, high-efficiency natural gas combined cycle systems. This is certainly one of the challenges faced by the industry today. Deregulation is likely to bring many opportunities as well as challenges however. Among these are capturing the market for "green power" demonstrated by innumerable public surveys. Also promising is deployment of these technologies into the cogeneration and distributed generation markets. This avoids head-to-head competition with large central station fossil-fueled plants. Additionally, such systems may have access to low cost feedstocks or favorable treatment by regulatory bodies. Smaller scale distributed generations systems employing industrial turbines or fuel cells are also applicable to the burgeoning international market for electricity generation.

Advanced utilization systems are currently under development that hold the potential for even more significant improvements in cost and efficiency than the systems examined here. It is important to continue development and demonstration of current technology and dedicated feedstock supply systems to be positioned to take advantage of these advances.

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